CALIFORNIA ENERGY COMMISSION

2008 INTEGRATED ENERGY POLICY REPORT UPDATE

DRAFT COMMITTEE REPORT

SEPTEMBER 2008
CEC-100-2008-008-CTD

Arnold Schwarzenegger, *Governor*

CALIFORNIA ENERGY COMMISSION

INTEGRATED ENERGY POLICY REPORT COMMITTEE

Commissioner Jeffrey Byron
Presiding Member

Chairman Jackalyne Pfannenstiel
Associate Member

Gerry Braun
Pamela Doughman
Judy Grau
Michael Jaske
Chris Kavalec
Suzanne Korosec
Rachel MacDonald
Jamie Patterson
Mike Ringer
David Vidaver
Jennifer Williams
Primary Authors

Melissa Jones
Executive Director

DISCLAIMER

This draft report was prepared by the California Energy Commission's Integrated Energy Policy Report Committee as part of the *2008 Integrated Energy Policy Report Update* proceeding. The views and recommendations contained in this document are not official policy of the Energy Commission until the report is adopted.

Please cite this report as:

California Energy Commission 2008, *2008 Integrated Energy Policy Report Update*, CEC-100-2008-008-CTD.

Abstract

The *2008 Integrated Energy Policy Report Update* addresses the following five topics related to California's energy systems:

1. What physical, operational, and market changes will be needed for California's electric system to support a minimum of 33 percent renewables by 2020.
2. How the state's energy efficiency goals and programs interact with the Energy Commission's electricity and natural gas demand forecasting methods.
3. Recommended changes to electricity procurement practices to standardize assumptions, extend the period of analysis, and more adequately incorporate risk in the portfolio of projected resources.
4. Potential vulnerability of Diablo Canyon Power Plant and San Onofre Nuclear Generating Station nuclear power plants to a major disruption from a major seismic event or plant aging, as required by Assembly Bill 1632.
5. Evaluation of the California Public Utilities Commission's Self-Generation Incentive Program (SGIP) to determine the costs and benefits of providing ratepayers subsidies for renewable and fossil fuel "ultraclean and low-emission distributed generation" as required by Assembly Bill 2778.
6. Status report on recommendations made in past Integrated Energy Policy Reports.

Key Words

Renewables Portfolio Standard, Renewable Energy Transmission Initiative, renewable energy, energy efficiency, demand forecast, electricity procurement, portfolio planning, social discount rate, nuclear power plants, aging power plants, once-through cooling, Self-Generation Incentive Program, distributed generation, combined heat and power.

Table of Contents

EXECUTIVE SUMMARY

Senate Bill 1389 (Bowen and Sher, Chapter 568, Statutes of 2002) requires the California Energy Commission (Energy Commission) to "conduct assessments and forecasts of all aspects of energy industry supply, production, transportation, delivery and distribution, demand, and prices." The Energy Commission uses these assessments and forecasts to develop energy policies that conserve resources, protect the environment, ensure energy reliability, enhance the state's economy, and protect public health and safety. The Energy Commission prepares these assessments and associated policy recommendations every two years, with updates in alternate years.

The *2008 Integrated Energy Policy Report Update* assesses progress on energy programs and policy recommendations critical to meeting California's energy and related environmental goals. The Integrated Energy Policy Report Committee identified critical energy topic areas for the *2008 Integrated Energy Policy Report Update* at a scoping hearing on April 28, 2008. After considering stakeholder feedback, the Integrated Energy Policy Report Committee decided to address the following five topic areas:

1. Physical, operational, and market changes necessary for California's electric system to support a minimum of 33 percent renewables by 2020.
2. Interaction of the state's energy efficiency goals and programs and the Energy Commission's demand forecasting methods.
3. Status of recommended changes to electricity procurement practices to standardize assumptions, extend the period of analysis, and more adequately incorporate risk in the portfolio of projected resources.
4. Assessment of the Diablo Canyon Power Plant and San Onofre Nuclear Generating Station nuclear power plants to determine the potential vulnerabilities to a major disruption from a major seismic event or plant aging, as required by Assembly Bill 1632 (Blakeslee, Chapter 722, Statutes of 2006).
5. Evaluation of the California Public Utilities Commission's Self-Generation Incentive Program to determine the costs and benefits of providing ratepayers subsidies for renewable and fossil fuel "ultraclean and low-emission distributed generation" as required by Assembly Bill 2778 (Lieber , Statutes of 2006, Chapter 617).

The *2008 Integrated Energy Policy Report Update* also provides a status report on policy recommendations made in past Integrated Energy Policy Reports. This review is intended to ensure that California is on track in meeting the state's energy policy goals while meeting California's need for affordable, safe, and environmentally acceptable energy choices.

California's Renewable Future

California has a mandate to increase the use of renewable generation to 20 percent of retail electricity sales by 2010. The Governor and the state's energy agencies have identified a further target of 33 percent renewable generation by 2020, which will help the state meet the aggressive greenhouse gas emission reduction target of 1990 levels by 2020.

The Energy Commission believes the state can reach the 33 percent renewables target by 2020. However, significant barriers to achieving this goal include: the need for transmission additions and upgrades to access renewable resource areas; the challenges associated with integrating large amounts of renewable resources into the state's electricity system; the impacts of renewable contract delays or cancellations; potential cost and rate impacts of adding renewables to the system; and permitting issues for renewable generation facilities in environmentally sensitive areas.

The Renewable Energy Transmission Initiative was established to help address transmission barriers by identifying and ranking renewable resource zones and broadly identifying the transmission needed to access those zones. Because environmental and land use issues can delay the development of transmission projects, the Energy Commission will continue to work closely with stakeholders in the Renewable Energy Transmission Initiative process to ensure that these issues are evaluated and considered. In addition, the Energy Commission recognizes the importance and benefits of joint transmission projects between investor-owned and publicly owned utilities, and will use the *2009 Integrated Energy Policy Report* process as a forum to help identify strategies to reduce barriers to these joint projects. Finally, transmission-related research, development, and demonstration efforts and funding should be significantly increased to help identify technologies and strategies that can facilitate the integration of renewable resources.

To address barriers to integrating large amounts of variable and intermittent resources like wind into California's electricity system, the state should focus on identifying energy storage technologies with the most promise to provide grid stability and improved operations, reducing the costs of those technologies, and increasing their commercialization. In addition, improved forecasting is needed to give grid operators the information they need to make real-time decisions on electricity scheduling and dispatch. The state should also expand efforts to include renewable generation at the distribution level, such as community-scale photovoltaics or small wind, which can reduce electricity loads as well as the need for upgrades to the transmission system. Similarly, increased use of renewable technologies for heating and cooling, like solar thermal water heating and geothermal ground-source heat pumps, could reduce electricity loads while also reducing the use of fossil fuels and their associated greenhouse gas emissions.

Renewable contract delays or cancellations continue to be a barrier to meeting California's renewable goals. Thirty percent of the contracts signed under the Renewables Portfolio Standard have been either delayed or cancelled, and there continues to be a need for greater transparency about signed contracts. The Integrated Energy Policy Report Committee recommends that the California Public Utilities Commission should conduct its own evaluations of renewable proposals without the participation of the investor-owned utilities, and that the investor-owned utilities should be required to provide aggregated information on Renewables Portfolio Standard contract prices, project locations, and schedules to assure policy makers that contracts are providing strategies and economic value to the state. In addition, the California Public Utilities Commission should make public the aggregate amount of above-market funds that are being allocated to Renewables Portfolio Standard contracts. To help encourage renewable development and provide price certainty to renewable developers, the Energy Commission and the California Public Utilities Commission should work collaboratively on developing a pilot program to provide standardized contracts and prices for renewable projects larger than 20 megawatts.

To better understand the cost and price impacts of a 33 percent renewable target, the Energy Commission will evaluate impacts of that level of renewables on natural gas demand and prices as well as the impacts of regional changes in natural gas supply and demand on California's natural gas market. The Energy Commission will also continue its work on its Cost of Generation Model to regularly update changing technology costs over time. Finally, the Energy Commission will work along with the California Public Utilities Commission to estimate potential price impacts of the 33 percent renewable target based on current contracts and scenarios using the Cost of Generation Model.

Energy Efficiency and Demand Forecasting

In the *2007 Integrated Energy Policy Report,* the Energy Commission identified the need to clarify and refine its California Energy Demand forecast. The *2008 Integrated Energy Policy Report Update* discusses the challenges involved in measuring and attributing the electricity savings resulting from energy efficiency programs and other market forces within the California Energy Demand Forecast; provides an overview of methods currently used by Energy Commission staff to incorporate energy efficiency programs into the forecast; identifies the approach Energy Commission staff will use to clarify the efficiency assumptions in the demand forecast within the *2009 Integrated Energy Policy Report* cycle and beyond as recommended in the *2007 Integrated Energy Policy Report;* and reports on progress made by California utilities in fulfilling the efficiency requirements of Assembly Bill 2021 (Levine, Chapter 734, Statutes of 2006), which set a statewide goal of reducing total forecasted electricity consumption by 10 percent over the next 10 years.

For the *2008 Integrated Energy Policy Report Update*, the Integrated Energy Policy Report Committee directed the Energy Commission staff to:

- Clearly explain how energy efficiency is incorporated in the demand forecast, allowing parties to understand how the models include utility programs, standards, and other efficiency codes as inputs when developing the demand forecast.
- Evaluate price response, market effects, and trends in the market, and how they are included or excluded from the demand forecast models.

- Clarify the amount of efficiency program savings or potential embodied in the forecast and how it will effect decisions to go forward with additional efficiency programs.
- Evaluate potential new project capabilities to use with the demand forecast to examine long-term alternative energy efficiency strategies, such as zero-emission building goals, in support of long-term greenhouse gas reduction goals.
- Identify what collaboration is needed or desirable among utilities, the California Public Utilities Commission, the Energy Commission, and others to refine demand forecasting methods and create needed energy efficiency projection capabilities.

The staff has begun a process to make efficiency attribution and measurement more transparent to users of the demand forecast, refine and improve modeling methods, and develop efficiency measurement capabilities not currently part of the forecasting process. During the *2009 Integrated Energy Policy Report* cycle, staff will:

- Develop a standardized taxonomy of terms encompassing all major concepts applying to efficiency potential studies and energy demand forecasts. (September - November 2008)
- Organize and participate in a stakeholder working group designed to address technical efficiency issues and to develop consistent metrics for efficiency analysis across utilities and various agencies. (Organized September 2008)
- Review and compare the modeling methods, inputs, and data sources used in Commission forecasts of efficiency savings with the Itron Asset Model. Compare interim savings estimates from the Energy Commission's demand forecast and the Itron Asset Model for selected programs given common sets of input and modeling assumptions. (September - November 2008)
- Refine and improve the Energy Commission's forecasting models to allow more detailed and complete output of committed efficiency savings. (December - June, 2009)
- Investigate alternative forecasting methods (Ongoing)
- Develop an uncommitted energy efficiency projection capability. (June-July, 2009)

To improve the Energy Commission's demand forecast in the future, the Integrated Energy Policy Report Committee believes the *2009 Integrated Energy Policy Report* should compare how end-use impacts are characterized in the Energy Commission's demand forecast and in efficiency program planning. Ignoring potential overlap will result in misleading estimates of how much can be achieved through future efficiency strategies. In addition, investor-owned utilities and publicly owned utilities, regulatory agencies, and other interested stakeholders should participate in the working group established in September 2008 that will focus on technical issues and effectively communicating results to all interested stakeholders. Further, independent efforts to investigate and evaluate alternate forecasting methods should be continued in the *2009 Integrated Energy Policy Report* and focus on matching methods to the various purposes to which the demand forecast is applied.

The Energy Commission staff should continue to work with publicly owned utilities to understand the processes used by individual utilities to estimate their remaining economic energy efficiency potential and set efficiency targets. The Energy Commission staff should also continue to assist the publicly owned utilities in achieving their efficiency goals through workshops and collaborative efforts that improve overall evaluation planning, develop program tracking systems and improve savings reporting requirements for the next Assembly Bill 2021 cycle.

Electricity Procurement Practices and Resource Planning Activities

The *2007 Integrated Energy Policy Report* raised concerns about electricity procurement in California and made recommendations to address those concerns. The *2008 Integrated Energy Policy Report Update* discusses progress made in implementing those recommendations and discusses reliability and resource adequacy issues associated with moving away from the use of once-through cooling in power plants and the relationship between electricity procurement and the Energy Commission's power plant siting process.

Every two years, the major investor-owned utilities must submit 10-year plans to the California Public Utilities Commission for procuring electricity. The plans submitted in December 2006 for 2007 through 2016 were criticized by various parties because the plans did not allow for comparison across utilities, nor did they adequately evaluate high natural gas prices and greenhouse gas regulation that represent significant ratepayer risk. The California Public Utilities Commission acknowledged the shortcomings in the procurement planning process and in the 2008 long-term procurement plan proceeding is directing the investor-owned utilities to provide a set of plans in 2010 that can be compared and aggregated and that also consider ratepayer risks. The California Public Utilities Commission has developed a set of principles that reflect their desire to evaluate utility portfolios using a standardized, transparent methodology that reflects uncertainties like future natural gas prices and carbon costs.

The Integrated Energy Policy Report Committee recommends that Energy Commission staff continue to collaborate in the California Public Utilities Commission's long-term procurement plan proceeding. In addition, the *2009 Integrated Energy Policy Report* should assess longer-run (20-year) uncertainties related to electricity demand and natural gas prices and supply. As the California Public Utilities Commission's 2008 procurement proceeding moves forward, other issues related to resource planning beyond 2020 may also need to be included in the *2009 Integrated Energy Policy Report*, such as exploring how to overcome constraints faced by utilities in reducing the carbon footprint of their portfolios over the long run.

Another issue related to procurement identified in the *2007 Integrated Energy Policy Report* was how current methods for estimating future natural gas fuel costs, specifically the discount rate used, makes these costs appear unrealistically inexpensive. This could lead to increased dependence on natural gas-based generation because alternatives such as renewables and efficiency would be undervalued. The *2007 Integrated Energy Policy Report* recommended applying a 3 percent social discount rate (lower than the current discount rate based on a utility's cost of capital) to future natural gas costs to more accurately reflect the risks of cost volatility of natural gas-based generation. For the *2008 Integrated Energy Policy Report Update*, the Integrated Energy Policy Report Committee directed staff to explore the consequences of using a social discount rate.

There is general agreement about the importance of incorporating uncertainty and risk, including fuel price uncertainty, into the overall planning and decision-making process. The Energy Commission anticipates that the California Public Utilities Commission will require the next round of long-term procurement plans to incorporate risk-based portfolio analysis by reflecting a wide range of future natural gas prices and associated gas price risk. The Energy Commission staff will continue to collaborate with California Public Utilities Commission staff to ensure that fuel price risk is properly considered in constructing utility portfolios. The Integrated Energy Policy Report Committee believes that the planning process is a more direct and transparent method to account for potential gas price risk than the adjustment of discount rates, and recommends that social discount rates should not be used to incorporate natural gas price risks. However, the California Public Utilities Commission should consider using risk-adjusted discount rates to compare projects selected in utility solicitations when making refinements in how to evaluate bids in the long-term procurement proceeding .

A third major issue related to electricity procurement is the potential impacts on electricity reliability from the retirement or repowering of aging power plants combined with restrictions on the use of once-through cooling in existing and new power plants. In March 2008, the State Water Resources Control Board issued a draft proposal calling for the phased elimination of once-through cooling between 2015 and 2021, with a final proposal expected in January 2009. Accomplishing this could require the refitting, repowering, replacement, or retirement of 19 power plants representing nearly 40 percent of the state's electricity generating capacity.

Aging plant retirement, or repowering and transmission line upgrades, are subjects of an ongoing California Independent System Operator study to be completed in early 2009. Additional analysis is needed on the implications of replacing much of the once-through cooling capacity with preferred resources , such as renewables, and natural gas-fired generation that can be dispatched on demand to meet local capacity and grid stability needs. The *2009 Integrated Energy Policy Report* may need to evaluate how repowering, replacement or retirement of aging and once-through cooling plants interacts with the development of preferred resources like renewable, as well as the implications of relying on once-through cooling and aging plants for energy and local capacity needs, particularly in the Los Angeles basin.

The final procurement issue relates to how utilities consider progress in the permitting process when evaluating what projects to select for procurement. In the past, some projects selected to receive contracts faced significant siting and environmental issues that threatened project viability, timely construction, or cost. In the best interest of utility shareholders and ratepayers, projects competing in a solicitation should understand the siting-related criteria that will be used to judge them. In addition, projects should have a high probability of being permitted in the required time frame without major environmentally-related modifications or cost increases.

The Integrated Energy Policy Report Committee recommends that the California Public Utilities Commission should conduct a fully transparent method of ranking projects in the bid evaluation phase of solicitations that identifies how they consider project permitting in both the planning and permitting phases. As part of the *2009 Integrated Energy Policy Report*, the Energy Commission will conduct a public process and invite the California Public Utilities Commission to help develop criteria for incorporating a project's progress in planning or permitting into the bid evaluation in utility solicitations. The siting-related criteria that are developed should apply to all projects that participate in a solicitation, including those not under Energy Commission jurisdiction. The criteria should encompass all permitting issues that could result in project termination, delay, or cost increases.

Assessment of California's Operating Nuclear Plants

Assembly Bill 1632 directs the Energy Commission to assess the potential vulnerability of "large baseload generation facilities of 1,700 megawatts or greater" to a major disruption due to a seismic event or plant age-related issues. The Energy Commission is directed to adopt this assessment on or before November 1, 2008, and include it in the *2008 Integrated Energy Policy Report Update*.

California's two operating nuclear facilities, the Diablo Canyon Power Plant and the San Onofre Nuclear Generating Station, fall under the AB 1632 requirement. Although two natural-gas fired facilities, Alamitos and Moss Landing, have a nameplate capacity greater than 1,700 megawatts, both of these facilities operate below a 60 percent capacity factor and are therefore not considered baseload facilities and not included in the Assembly Bill 1632 assessment.

The Diablo Canyon Power Plant and the San Onofre Nuclear Generating Station represent 12 percent of California's overall electricity supply. A major disruption because of an earthquake or plant aging could result in a shutdown of several months up to more than a year or even cause the retirement of one or more of the plants' reactors. Because these plants are so important to the state's electricity supply, California needs a long-term plan should such a disruption occur.

The Energy Commission and its consultant MRW & Associates developed a study plan for the *Assembly Bill 1632 Assessment of California's Operating Nuclear Plants* in January 2008. The Energy Commission held a public workshop on September 25, 2008, on the draft consultant report, and the Energy Commission's Electricity and Natural Gas Committee will develop its draft Committee report based on the consultant study and public comments received. The Energy Commission will release the draft Committee Report in October and hold a public workshop on the report in late October. The Energy Commission expects to adopt the final *Assembly Bill 1632 Assessment of California's Operating Nuclear Plants* in November 2008, and the final findings and recommendations from that report will be included in the adopted *2008 Integrated Energy Policy Report Update*. In the interim, this draft *2008 Integrated Energy Policy Report Update* includes preliminary findings but no specific recommendations.

Evaluation of the Self-Generation Incentive Program

Assembly Bill 2778 requires the Energy Commission, in consultation with the California Public Utilities Commission and the California Air Resources Board, to evaluate the California Public Utilities Commission's Self-Generation Incentive Program and the costs and benefits of expanding eligibility for the program to renewable and fossil fuel distributed generation. The Self-Generation Incentive Program is one of the largest distributed generation incentive programs in the United States, with approximately 1,200 projects totaling 300 megawatts on-line by the end of 2007; only fuel cells and wind energy technologies are currently eligible for the program.

The *2008 Integrated Energy Policy Report Update* summarizes preliminary findings on the costs and benefits of the SGIP and provides recommendations to improve the program by using new storage technologies to capture excess generation for use during peak times, extending eligibility to other clean technologies such as combined heat and power, and revising the incentive structure to better meet the state's energy policy goals.

The Energy Commission's consultant TIAX LLC is conducting the evaluation of the Self-Generation Incentive Program. TIAX identified limited environmental benefits from air quality and climate change perspectives aside from the previously funded photovoltaic generation. Benefits from greater economic activity within California include more than $1 billion in value added to the state as well as other economic benefits such as job creation and income benefits.

Based on the preliminary results of the TIAX evaluation, the Integrated Energy Policy Report Committee believes that eligibility for the Self-Generation Incentive Program should be based on the overall efficiency and performance of systems regardless of fuel type. In addition, the California Public Utilities Commission should consider re-instituting formerly eligible technologies that operate on landfill gas, digester gas from dairy waste or waste-water treatment processes, or biodiesel. TIAX's review of other technologies and fuel types also suggests that the California Public Utilities Commission should consider providing self-generation incentives for energy storage technologies, since these technologies provide capacity benefits.

Distributed generation can have location-specific grid benefits when sized correctly. The transmission and distribution costs avoided by such systems can be quantified with highly accurate customer and utility data. There should be further study in this area to quantify the locational benefits of distributed generation, but in the meantime the Integrated Energy Policy Report Committee believes that the California Public Utilities Commission should require investor-owned utilities to meet a portion of their distribution system upgrades by procuring distributed generation or combined heat and power in areas that provide these benefits to the distribution system.

The Integrated Energy Policy Report Committee also reiterates recommendations made in past Integrated Energy Policy Reports to encourage policies that support market penetration of combined heat and power systems in California.

State Progress on Key Integrated Energy Policy Report Recommendations

The *2008 Integrated Energy Policy Report Update* is a real-time, public forum for continuing dialog about California's energy policies. This update examines the progress the state has made in addressing key recommendations made in past Integrated Energy Policy Reports on electricity and procurement issues, energy efficiency requirements, demand response, load management standards, renewable energy issues and goals, distribution system and combined heat and power, nuclear power, transmission, natural gas, transportation, petroleum infrastructure, land use, and water/energy. The *2008 Integrated Energy Policy Report Update* ranks the progress of each recommendation as "substantial," "on track," or "needs improvement," and describes the current progress on each recommendation.

CHAPTER 1: California's Renewable Energy Future

Introduction

California has made electricity generation from renewable resources a priority since the 1970s and leads the nation in biomass, geothermal, and solar capacity and generation. In addition to the environmental benefits from reducing the burning of fossil fuels, using renewable resources reduces the risks and costs associated with high and volatile natural gas prices while also decreasing the state's reliance on imported natural gas as a fuel for electricity generation. Renewable resources also provide other benefits such as economic development and new employment opportunities.

Renewable energy is an essential component of the state's loading order for meeting growing energy needs – first with energy efficiency and demand response; second, with renewable energy and distributed generation; and third, with clean fossil-fueled sources and infrastructure improvements. California currently has a Renewables Portfolio Standard (RPS), which requires electric utilities to increase the use of renewable generation to 20 percent of retail electricity sales by 2010. The Governor and the state's energy agencies have identified a further target of 33 percent renewable generation by 2020, which the California Air Resources Board (ARB) has identified as a key strategy for meeting the state's aggressive greenhouse gas (GHG) emission reduction target of 1990 levels by 2020.[1] To help meet the Governor's goal to reduce GHG emissions to 80 percent below 1990 levels by 2050,[2] California needs to achieve even higher renewable generation goals.

The *2007* Integrated Energy Policy Report (*2007 IEPR)* found that "the 33 percent goal by 2020 is feasible, but only if the state commits to significant investments in transmission infrastructure and makes some key changes in policy." The priority now is to identify the obstacles to reaching that goal and determine how to overcome those obstacles. The state needs to develop an appropriate package of policy reforms that will help get it on track for meeting the 33 percent RPS target while continuing to deliver reliable and affordable power to Californians.

In the *2008 Integrated Energy Policy Report Update (2008 IEPR Update*), the IEPR Committee is concentrating its efforts on what useful information can be gleaned from prior or ongoing studies on this topic, what analysis is needed to better understand how the 2020 system should be structured to accommodate higher levels of renewables, identifying major barriers to renewable development, what research and development efforts will be needed to support higher renewable targets, and how the state's energy agencies can coordinate their efforts to develop strategies to overcome barriers.

---

1 Draft Scoping Plan prepared by the California Air Resources Board as required by the Global Warming Solutions Act (Assembly Bill 32 [Núñez, Chapter 488, Statutes of 2006]), http://www.arb.ca.gov/cc/scopingplan/document/draftscopingplan.htm.

2 Governor's Executive Order S-3-05, June 2005, http://gov.ca.gov/executive-order/1861/.

In addition to the investor-owned utilities' role in meeting the state's renewable energy goals, the role of publicly owned utilities is also extremely significant. These entities provide 25–30 percent of the retail electricity sold in California, making their participation essential to meeting statewide renewable and GHG reduction goals. There is, therefore, a need to work with the publicly owned utilities to understand their plans for helping the state to meet the 33 percent goal by 2020, and their views on challenges, opportunities, and changes needed to achieve even higher levels of renewables.

Barriers to Renewable Development

The primary barrier to increased development of renewable resources continues to be lack of transmission to access these resources, particularly in remote areas of the state. The Renewable Energy Transmission Initiative (RETI), discussed later in the chapter, was put in place to address this barrier by facilitating and coordinating the planning and permitting of transmission and generation projects needed to further the state's renewable policy goals.

There are also emerging technologies that can be used to optimize operation of the existing transmission system by increasing the carrying capacity of existing lines or by providing real-time information to grid operators about system outages or potential areas of congestion to allow better management of the grid. In addition, using a "smart grid" can improve efficiency, reliability, and cost-effectiveness of the transmission and distribution system by using advanced sensing, communication, and control technologies. Another major barrier to meeting the 33 percent goal is how to integrate large amounts of variable and intermittent renewable resources, such as wind and solar, into California's electricity system. These technologies pose challenges to traditional reliability planning and resource adequacy requirements because they cannot be relied on to meet rapid changes in load and supply during peak hours and generally must be backed up with dispatchable resources. Also, wind resources can produce large amounts of energy during low demand times, which, when combined with generation from existing conventional baseload plants with must-run contracts and baseloaded nuclear power plants, can lead to an overgeneration problem. Energy storage technologies can help firm up variable technologies, while data management and display systems can give grid operators real-time information to allow them to respond to the unpredicted changes in output that are characteristic of some renewable technologies.

There is also the potential for wide-scale use of renewable generation at the distribution level, such as community-scale photovoltaics or small wind. Behind-the-meter generation has the same effect as energy efficiency in reducing load and can help avoid or defer the need for transmission system upgrades. Similarly, using renewable technologies for heating and cooling, like solar thermal water heating and geothermal ground source heat pumps, can reduce electricity loads while also reducing the use of fossil fuels and their associated greenhouse gas emissions. The risk of renewable contract delays or cancellations represents another barrier to renewable development. As of July 2008, the California Public Utilities Commission (CPUC) had approved 95 contracts for 5,900 megawatts (MW) of new and existing renewable generating capacity.[3] However, only about 400 MW of that contracted capacity is currently operational, and approximately 30 percent of contracts signed since 2002 are either delayed (25 percent) or have been cancelled (4 percent), making it extremely unlikely that the state will meet its 2010 goals. [4]

A further barrier to renewable development is the concern that transitioning to 33 percent renewable will result in higher costs to ratepayers. However, the issue here is how to compare the incremental costs of a 33 percent future with potential cost increases that may occur even without added renewables, depending on future natural gas prices, potential costs of carbon regulation, generation costs in general, and needed upgrades to the transmission and distribution system.

Environmental permitting issues related to large-scale renewable development remain a major concern. Many energy projects are being proposed on public lands overseen by the federal Bureau of Land Management (BLM). As of July 2008, the BLM has received 75 solar applications and 94 wind applications totaling about 1.3 million acres of land.[5] For comparison, 1,441 acres have been impacted by power plants (primarily natural-gas fired) currently operating or under construction that have been permitted by the Energy Commission since 1996. Given the sensitive nature of some of these lands, there may be significant habitat impacts requiring mitigation measures. Identifying enough habitat land to reduce the potential impacts of these projects will be a challenge depending on the species impacted and uncertainty on how to account for the costs of mitigation measures is a major concern for renewable developers.

In addition, with recent increased interest from investors in renewable energy as a result of climate change concerns and high fossil fuel prices, new and inexperienced developers may be entering the market who are unfamiliar with the California Environmental Quality Act, plant development issues, and the unique challenges of siting generating facilities in California. The CPUC has identified this risk in its quarterly reports to the Legislature on the RPS, and its April 2008 report[6] noted that, "Many new, inexperienced developers have difficulty understanding and navigating the complex project development process…", and many approved contracts have been resubmitted with price reopeners possibly "…because the original bid had simply underestimated project development realities."

---

3 California Public Utilities Commission, July 2008, *Renewables Portfolio Standard Quarterly Report to the Legislature*, http://docs.cpuc.ca.gov/word_pdf/REPORT/85936.pdf.

4 California Energy Commission, Database of IOU Contracts for Renewable Generation, July 2008 update, www.energy.ca.gov/portfolio/IOU_CONTRACT_DATABASE.XLS.

5 Comments from Bob Doyel, Bureau of Land Management, July 23, 2008, IEPR staff workshop, http://www.energy.ca.gov/2008_energypolicy/documents/2008-07-23_workshop/2008-07-23_TRANSCRIPT.PDF, page 89.

6 California Public Utilities Commission, April 2008, Renewables Portfolio Standard Quarterly Report to the Legislature, http://www.cpuc.ca.gov/PUC/energy/electric/RenewableEnergy/documents.htm.

Addressing Transmission Barriers

Every two years, the Energy Commission adopts a strategic plan for the state's electric transmission grid that identifies and recommends actions required to implement investments to ensure reliability, relieve congestion, and meet future growth in load and generation, including renewable resources. [7] The *2007 Strategic Transmission Investment Plan (2007 Strategic Plan)* recommended 10 specific near-term transmission projects that improve system reliability, reduce congestion, and or interconnect renewable resources. Eight of those projects have the ability to interconnect renewables or provide operational flexibility to allow the transmission system to better integrate intermittent generation from renewables.[8]

The *2007 Strategic Plan* also identifies the need to remove transmission barriers to renewables. The plan recommended active Energy Commission participation in RETI, a three-phase process which was initiated in September 2007 with the goal of identifying preferred renewable resource zones for generating projects and the transmission infrastructure needed to access those zones.[9]

Phase 1 of RETI, to be completed in fall 2008, will screen and rank potential renewable resource zones and broadly identify transmission needed to access these zones and has been subdivided into two tasks: Phase 1A, to define the resource assessment method, study assumptions, and resources to be considered in the project-level analysis, and Phase 1B, to use the method developed in Phase 1A to group the identified resources into competitive renewable energy zones. Phase 2, to be completed in spring 2009, will examine generation and transmission in more detail and will develop transmission plans in concept to the top ranking zones. Phase 3, to be completed in 2010, will flesh out those conceptual plans and support transmission owners in developing detailed plans of service for commercially viable transmission projects and establish the basis for regulatory approvals of specific transmission projects.

The Energy Commission's participation in RETI is crucial in ensuring that the plans resulting from RETI reflect environmental, siting, and permitting perspectives to reduce impacts that could delay renewable energy projects.

---

7 As required by Senate Bill 1565 (Bowen, Chapter 692, Statutes of 2004).

8 The eight projects are San Diego Gas & Electric's Sunrise Powerlink 500 kV Project; Southern California Edison's Tehachapi Renewable Transmission Plan (Segments 1 through 3 in the *2005 Strategic Plan* plus the remaining segments in the *2007 Strategic Plan*); the Imperial Valley Transmission Upgrade Project; Pacific Gas and Electric Company's Central California Clean Energy Transmission Project; the transmission component of the Lake Elsinore Advanced Pumped Storage Project; the Green Path Coordinated Projects; and the Los Angeles Department of Water and Power Tehachapi Project.

9 The Renewable Energy Transmission Initiative was initiated as a collaborative effort between the Energy Commission, the California Public Utilities Commission, the California Independent System Operator, the Northern California Power Agency, the Southern California Public Power Authority, and the Sacramento Municipal Utility District and has a diverse stakeholder committee composed of representatives from California's investor-owned and publicly owned utilities, renewable developers, environmental organizations, landowners, Native American representatives, transmission owners and providers, the military, and federal, state, and local agencies.

The *2007 Strategic Plan* also recommended that the Energy Commission encourage corridor applications that would provide access to renewable resource areas. The Energy Commission is responsible for designating transmission corridors on non-federal lands in advance of need to help streamline future permitting of transmission projects[10] and is the lead agency for preparing an environmental assessment of proposed transmission corridors. In situations where RETI indicates the need for a transmission line seven or more years in the future, the Energy Commission's transmission corridor designation process can provide a bridge to the eventual permitting of transmission projects.

The Energy Commission staff held a workshop on July 23, 2008, to discuss transmission barriers for renewables and identify key issues for the *2009 Strategic Transmission Investment Plan*. Workshop participants identified several major barriers to achieving the state's renewable goals. First, there is a need for mechanisms to remove barriers to joint transmission projects between publicly owned utilities and investor-owned utilities (IOUs). Second, with regard to transmission siting, the state must continue to actively address environmental, land use, and local public opposition issues by working closely with stakeholders.

Stakeholders agreed that RETI is proving to be a valuable forum for reaching consensus on the high-priority competitive renewable energy zones and the necessary transmission to reach them. Stakeholders also noted the potential for overlap between RETI and other forums and the limited amount of resources available to devote to the many forums, and encouraged coordination between efforts to avoid duplication.

Joint Transmission Projects

California's publicly owned utilities have raised concerns about obstacles to joint transmission development in the West between the state's publicly owned utilities and IOUs subject to the California Independent System Operator's (California ISO) tariffs. According to the publicly owned utilities, unless these concerns are resolved, joint transmission projects will not be developed that could help achieve the state's renewable and GHG reduction policy goals. This issue was discussed at the July 23, 2008, IEPR staff workshop on transmission issues, and there was general consensus from multiple parties that this is an institutional barrier that needs to be addressed and resolved to achieve state policy objectives.[11]

Following the workshop, the California Municipal Utilities Association (CMUA), Imperial Irrigation District (IID), Los Angeles Department of Water and Power (LADWP), and Sacramento Municipal Utility District (SMUD) filed joint comments describing some of the legal and market obstacles to joint ownership. The joint commenters note that publicly owned

---

10 As authorized by Senate Bill 1059 (Escutia and Morrow, Chapter 638, Statutes of 2006).

11 This issue was also identified by California ISO in its December 21, 2007, Order 890 Compliance Filing to the Federal Energy Regulatory Commission (FERC). In that filing, both SCE and the Transmission Agency of Northern California (TANC) raised specific concerns with the language in Section 24.11 of the Draft Market Redesign and Technology Update (MRTU) tariff. California ISO's response in the December 21, 2007, Order 890 Compliance Filing indicated that it intended to revise the language in Section 24.11 to "reflect the appropriate level of flexibility to facilitate jointly-owned transmission projects."

utilities typically negotiate contract-based transmission rates for joint projects and contend that the constantly changing nature of the California ISO tariff does not provide the same degree of cost certainty, rate predictability, and asset optimization as bilateral contract agreements. The joint commenters also noted that the California ISO is moving toward locational marginal pricing that uses financial rights, such as congestion revenue rights that can be risky and speculative, rather than firm physical rights to a specified amount of transmission line capacity. Furthermore, publicly owned utilities are concerned about California ISO's insistence on having full control of joint-ownership lines, as well as its requirement that all individual owner capacity and associated use must be subject to the California ISO tariff. The CMUA understands that this provision is being interpreted to bar joint ownership unless the line is within the electric footprint of the California ISO balancing authority.

Included in the joint comments was a July 2008 white paper prepared by IID, LADWP, SMUD, Turlock Irrigation District (TID), and the Western Area Power Administration titled *Experiences with Joint Transmission-Project Development in the West*. The paper describes recent joint development challenges faced by the Green Path Southwest and Green Path North projects and proposes a hybrid model for bridging the differences between the California ISO tariff and a contract-based arrangement.

The joint parties' comments and white paper were the focus of a roundtable discussion at the August 21, 2008, Joint IEPR and Renewables Committee Workshop on achieving higher levels of renewables in California's electricity system. Roundtable participants included SMUD, LADWP, IID, TID, and California ISO representatives. The publicly owned utility panel participants described the difficulties with the Green Path Southwest and Green Path North projects and identified the California ISO tariff requirements as one reason for the failure of these projects to go forward as joint projects.

The California ISO noted that its mission is to ensure the full and efficient use of transmission assets and promote infrastructure expansion and development to achieve the greatest benefits for California and California ISO ratepayers. The California ISO accomplishes this mission through tariff provisions that incorporate system operations and planning goals based on transparent reliability and economic objectives, and simultaneously provides mechanisms to accommodate jointly owned projects governed by bilateral agreements between the California ISO or its participating transmission owners and other parties. It also noted that its Location Constrained Resource Interconnection tariff provisions require it to avoid duplication of facilities and to coordinate with neighboring control areas if the new transmission facility is in a region that also connects to the California ISO system. [12]

The California ISO also submitted written comments after the workshop to emphasize its position. In those comments, California ISO stated that key principles in carrying out its day-to-day operations and transmission responsibilities include: costs borne by California ISO

12 The Location Constrained Resource Interconnection tariff was developed by the California ISO to facilitate financing and construction of transmission facilities needed to develop location-constrained resources, such as renewables. See http://www.caiso.com/1816/1816d22953ec0.html.

ratepayers must provide commensurate benefits; existing transmission should be fully used before new transmission expands the environmental footprint; and continued cooperation across the West is critical. California ISO also stated that its tariff specifically provides for bilateral agreements between owners of transmission under the California ISO's control and other parties, including publicly owned utilities.

The Energy Commission recognizes the importance and benefits of joint projects, especially to access renewable resources. In the *2007 Strategic Transmission Investment Plan,* the Energy Commission noted its concern that SCE's Tehachapi Renewable Transmission Plan and LADWP's Tehachapi Project could be duplicative unless the plans were coordinated and encouraged the two utilities to work together to avoid any overlap. Because there are both legal and market obstacles that hinder the development of joint projects, the IEPR Committee believes that the state should play a role in resolving these issues.

Environmental and Land Use Issues

At the July 23, 2008, IEPR staff workshop, the California ISO presented the results of its conceptual transmission planning study for connecting renewable generation to meet a 33 percent goal for the state's three IOUs.[13] The study identified the need for six new 500 kV transmission lines to meet the 33 percent goal through 2028 to 2030 at an estimated cost of about $6.5 billion.[14] Although these projects are conceptual only and will be refined as the RETI *Phase 1B Draft Resource Report* and Phase 2 results become available, they provide stakeholders with a sense of the scope, location, length, size, cost, and timing of possible transmission additions needed to meet the IOUs' portion of a statewide 33 percent renewables goal in 12 years.

However, many of the stakeholders at the workshop agreed that environmental and land use barriers are generally the biggest obstacles to the timely development of transmission projects. One stakeholder characterized the importance of understanding land use issues and environmental concerns during the transmission planning process this way: "…[W]e can all look at performing power flows till our faces are blue. But the real issue is going to be siting of that transmission facility."[15]

As noted earlier, in the *2007 Strategic Plan* the Energy Commission recommended that staff participate actively in RETI to ensure the resulting plan for preferred renewable resource zones for generation and electric transmission infrastructure reflects environmental, siting, and permitting perspectives. The Energy Commission will need to work closely with stakeholders during the RETI Phase 2 conceptual transmission planning process to ensure that they evaluate

---

13 These results are contained in Chapter 3 of the California ISO's August 6, 2008, *Report on Preliminary Renewable Transmission Plans*, available at: http://www.caiso.com/2007/2007d75567610.pdf.

14 Beyond the Southern California Edison Tehachapi Renewable Transmission Project and the San Diego Gas & Electric Sunrise Powerlink, which are currently undergoing review at the California Public Utilities Commission.

15 Comments from Jorge Chacon, Southern California Edison, July 23, 2008, IEPR workshop, http://www.energy.ca.gov/2008_energypolicy/documents/2008-07-23_workshop/2008-07-23_TRANSCRIPT.PDF,page 67.

and consider land use issues and environmental concerns when planning conceptual projects to access renewable resource areas.

Other stakeholders at the workshop noted that local opposition at both individual and institutional levels can make it difficult, if not impossible, to permit transmission projects that would be necessary to meet statewide policy goals. Parties stressed the need to educate the public and local governments on the importance of achieving the state's renewable and greenhouse gas reduction goals and the difficult choices that must be made to accomplish those goals. Regarding transmission projects, parties noted the need to communicate and work with affected local agencies, stakeholders, and the public well before a route is identified. The League of Women Voters offered that its 70 local leagues could assist local governments in developing energy elements for their general plans.[16]

Addressing Integration Barriers

Another major barrier to increasing the amount of renewables in California is how to integrate large amounts of variable resources, like wind and solar, into the system while maintaining grid stability, operation, and reliability. Unexpected drops in energy production require quick-start units to cover the shortfall, while unexpected increases require the ability to absorb the unscheduled generation. Procuring additional resources to support intermittent renewable resources will be needed, as will better forecasting techniques for wind and solar generation.

It is important to remember that not all renewable resources are intermittent. Geothermal and biomass power plants provide reliable, baseload power and can be integrated into the system without any additional backup. However, adding large amounts of any type of renewables to the system can still be problematic because California's local reliability requirements require load to be met primarily with local resources, and many renewable resources are located outside the state's 10 load centers.

One way to reduce the impacts of integrating renewables into the electricity system is through the use of distributed resources, which can reduce overall load, avoid or defer the need for transmission system upgrades, and reduce transmission and distribution losses. Using renewable resources to meet heating and cooling needs can also reduce electricity and natural gas loads while also reducing associated GHG emissions.

There are also a number of emerging technologies that can help integrate renewables into the electricity system, including energy storage technologies, better forecasting of variable resources, and technologies to improve the operation of the existing transmission system.

Results from Prior Integration Studies

At the IEPR workshops on achieving higher levels of renewables, Energy Commission staff summarized the findings from two recent studies on grid integration issues: the Energy

---

16 Comments by Jane Turnbull, League of Women Voters, July 23, 2008 IEPR workshop on transmission issues, http://www.energy.ca.gov/2008_energypolicy/documents/2008-07-23_workshop/2008-07-23_TRANSCRIPT.PDF, pp. 121-122.

Commission's *2007 Intermittency Analysis Project*[17] and the recent study by the Consortium for Electric Reliability Technology Solutions/Electric Power Group (CERTS/EPG). The California ISO also discussed its November 2007 study on the transmission and operational requirements to meet the 20 percent by 2010 renewable goal and plans for a study on the requirements to meet a 33 percent renewable scenario.

The Energy Commission's *Intermittency Analysis Project Final Report* evaluated what is needed for the transmission system to accommodate generation from 33 percent renewables by 2020. The Intermittency Analysis Project (IAP) evaluated reliability, load following capability, voltage support, and regulation, among other characteristics, for an assumed resource mix of 12,700 MW of wind, 5,100 MW of geothermal, 3,100 MW of concentrating solar power, 2,900 MW of solar PV, and 2,000 MW of biomass.[18] The study found that with significant expansion of transmission by 2020, it is feasible to operate the electricity system with 33 percent renewables. However, the study suggests that strategies will be needed to address periods of high and low load and found that there may be small additional costs associated with regulation and load following.

At the July 23, 2008, IEPR staff workshop on transmission issues, CERTS/EPG presented the results of its study to identify transmission and operating issues associated with integrating renewables.[19] CERTS/EPG calculated that California must integrate 20,000 MW of renewable capacity additions (relative to a 2006 base) to meet a statewide goal of 33 percent renewables by 2020. The study also suggested that 23,000 MW would be needed to continue to meet the 33 percent target in 2030 due to increased demand between 2020 and 2030. Furthermore, it found that a target of 50 percent renewables by 2030 would require 40,000 MW of renewable capacity additions. Based on these findings, the study focused on a mid-range value of 30,000 MW of additional renewables by 2030 as a reasonable starting point for examining system upgrades that would be necessary under that scenario.

CERTS/EPG observed that more than two-thirds of the 30,000 MW of additions would likely require delivery to transmission "gateways"[20] surrounding the Los Angeles Basin Area. The study concluded that gateway capacity would need to be tripled to integrate these renewable capacity additions, and other transmission links between regions would need to be expanded. From an operational perspective, local network reinforcements would also be required,

---

17 Final report available at http://www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081.PDF.

18 California Energy Commission, *Intermittency Analysis Project Final Report*, July 2007, page 18, http://www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081.PDF.

19 The report, currently in draft form, is tentatively titled "Renewable Resource Integration Project – Scoping Study of Strategic Transmission, Operations, and Reliability Issues." The essential information in the report is summarized in the CERTS/EPG July 23, 2008, staff workshop presentation, available at: http://www.energy.ca.gov/2008_energypolicy/documents/2008-07-23_workshop/presentations/John_Ballance%20Renewables_Integration.pdf.

20 Major L.A. Basin gateways are Antelope-Mesa, Vincent-Mesa/Vincent Rio Hondo, Lugo-Mira Loma, Palo Verde/Harquahala-Devers, Coachella/Ramon-Mirage, and San Diego-San Onofre.

including line upgrades, fault current limiters, breakers, and remedial action schemes.[21] The system would also need additional regulation and ramping ability, which could be addressed by energy storage, demand-side management, and automatic load control. Local voltage support could be enhanced by the addition of capacitors and dynamic voltage control devices. In addition, if plants in the Los Angeles Basin retire because of air or water restrictions, or if new non-renewable generation facilities are built outside the gateways, further increases in gateway capacity would be required.

CERTS/EPG made the following recommendations in its study:

- Further studies should expand the focus from evaluating just the interconnection of remote renewable resources to the grid to delivering that renewable energy all the way to the respective load centers.
- Policy makers need to provide guidance on resource type and location to allow timely integration of renewables and support early planning and upgrades of transmission gateway capacity and deliverability to load centers, aided by the RETI effort currently underway.
- Transmission owners and the California ISO need to move the planning horizon out to 15 to 20 years to define long-term gateway requirements, long-term transmission requirements from gateways into load centers, and interregional transmission requirements.
- Transmission owners and the California ISO need to initiate studies to expand transmission gateways and beyond into the load centers.
- Policy makers need information associated with the complete transmission integration requirement and cost implications for delivering all remote resources (both renewable and non-renewable) to the local load centers.
- The California ISO needs to provide utilities and the CPUC with guidance on the resource attributes needed for reliable operability of the grid.
- The state should evaluate the transmission requirements for transfer of renewable energy from the L.A. Basin area to San Diego and Northern California.

In November 2007, the California ISO conducted a study on operational changes needed to accommodate 20 percent renewables and believes that it can accommodate that level.[22] A study is planned on operational changes needed to accommodate 33 percent renewable electricity. According to the California ISO, the following areas need further examination:

---

21 Automatic protection systems designed to detect abnormal transmission system conditions and take corrective action to maintain system reliability.

22 California Independent System Operator, November 2007, Integration of Renewable Resources: Transmission and Operating Issues and Recommendations for Integrating Renewable Resources on the California ISO-controlled Grid, http://www.caiso.com/1ca5/1ca5a7a026270.pdf.

- Better wind and solar forecasting capability and better communication between forecasters and California ISO floor operators.
- Better understanding of the amount of ramping and regulation needed.
- Further information on the energy storage technologies that will be available.
- Exploration of changes to the California ISO market structure and tariffs to incentivize short-term storage for regulation flexibility.
- Assessment of whether the gas storage system can accommodate rapid swings in conventional generation needed to back up renewables, and how to communicate the need for additional natural gas quickly to the pipeline companies in response to weather-related drops in wind generation.

In addition, the California ISO suggested that more can be done to link renewables with demand side and thermal storage strategies. For example, the California ISO would like to see the ability to vary compressor loads for chillers in large buildings to help address variations in expected generation from wind or other variable renewable resources and suggested the state take a leadership role in retrofitting state buildings to provide this capability. This variable compressor load should be designed to allow the California ISO to send a signal requesting a building's compressor load to change in response to changes in expected generation.[23]

Resource Adequacy Requirements

California's resource adequacy requirements are intended to ensure uninterrupted electricity service to customers. There are two types of requirements, planning reserve margins and operating reserve margins. *Planning reserve margins* are long-term planning targets based on either the probability of a loss of load or the value of service. These targets are used to determine how much capacity is needed to maintain real-time operating reserves. *Operating reserve margins* relate to the ability to handle system fluctuations and disturbances. Operating reserve margins help balancing authorities, like the California ISO, ensure that voltage levels are maintained to prevent damage to transmission system components and uncontrolled cascading outages.[24]

Under the CPUC and California ISO resource adequacy requirement, each load-serving entity must demonstrate that it has enough generating capacity to cover 115 percent of expected monthly peak demand.[25] Generating resources have pre-established capacity values based on

---

23 Transcript of the July 21, 2008, IEPR Staff Workshop on Impacts of Higher Levels of Renewables on the Electricity System: Summary of Recent Studies. http://www.energy.ca.gov/2008_energypolicy/documents/2008-07-21_workshop/2008-07-21_TRANSCRIPT.PDF.

24 For more information, see California Energy Commission, May 2008, *Summer 2008 Electricity Supply and Demand Outlook*, Staff Report, CEC-200-2008-003, http://www.energy.ca.gov/2008publications/CEC-200-2008-003/CEC-200-2008-003.PDF.

25 The CPUC first adopted a broad resource adequacy requirement in D.04-01-050 as part of the series of decisions returning procurement authority to IOUs following the 2000-2001 electricity crisis. The initial framework for resource

their performance, known as the net qualifying capacity, which is used by load-serving entities when shopping around for electricity generation to meet resource adequacy requirements. Load-serving entities must secure 90 percent of their requirements one year ahead, and then demonstrate they have acquired the balance of their requirements one month ahead of each calendar month. This approach helps to ensure that the California ISO has enough resources to cover higher than expected loads, forced outages, and transmission outages.

This general framework has important implications for achieving high levels of renewable generation. Net qualifying capacity values for generating resources like wind and central station solar are established using a formula based on historic performance from hourly production data.[26] For wind resources, these values can be low because of the poor fit between performance and peak loads.[27] A low net-qualifying capacity value means that load-serving entities will be reluctant to select these resources to meet their renewable requirements unless the economic costs and benefits are better than those of other resource types.

Another facet of resource adequacy requirements is that, beginning in 2007, load-serving entities must meet local capacity requirements to ensure that the capacity needed by the California ISO is available in 10 separate load centers or pockets throughout the state. As a general rule, about 75 percent of total resource adequacy requirements must be satisfied with resources within these load pockets. Because renewable resources are location-specific and often remote, this requirement highlights the disadvantages of wind, central solar, geothermal, and biomass resources outside of these load pockets. Renewable developers should therefore be encouraged to locate projects where they can meet local capacity requirements, when feasible and cost-effective.

Distributed Renewables

Several parties at the IEPR renewables workshops asserted that there is tremendous opportunity for renewable generation at the distribution-level, at or near substations and on customer sites, or "behind the meter." However, most renewable generation from distributed resources, with the exception of facilities that are utility-owned or have specific power purchase contracts with a utility,[28] are not currently eligible for the state's RPS, though these technologies

---

adequacy for CPUC-jurisdictional entities (IOUs and Energy Service Providers) was established through D.04-10-035. Actual resource adequacy filing requirements began in late 2005 for the time period covering June – December 2006. A regular pattern of fall compliance filings for the subsequent calendar year was established, and has now been carried out for the 2007 and 2008 calendar years. Efforts for 2009 are underway. California ISO resource adequacy requirements paralleling those of the CPUC were established for the publicly owned utilities within its jurisdiction.

26 The California Energy Commission assesses individual project wind and solar performance data to compute the net qualifying capacity for these two resource types.

27 CPUC, Energy Division, 2006 Resource Adequacy Report, March 2007, indicates that on the six-day period July 21-26, 2006, when the California ISO system peak record was established, wind achieved between 145 and 533 MW, its net qualifying capacity was 608 MW, and nameplate capacity was 2,298 MW (p. 35).

28 The Energy Commission will certify facilities as RPS-eligible that would have been considered distributed generation facilities except that they are participating in a standard contract and tariff under CPUC Decision 07-07-027. This decision adopts tariffs and standard contracts for water, wastewater, and other customers to sell generation from RPS-eligible renewable resources up to 1.5 MW, up to a cumulative statewide total of 250 megawatts. See

do reduce retail sales and therefore the amount of renewable energy that must be procured to meet the RPS. While the CPUC has determined that 100 percent of the renewable energy credits (RECs) associated with renewable 'behind the meter' distributed generation projects belong to the system owners, generation from these systems cannot be counted toward RPS obligations until the CPUC authorizes the use of tradeable RECs for RPS compliance.

The California ISO has noted that when looking at a 33 percent goal, it is important to consider the contribution from behind-the-meter distributed solar installations, which could provide enough energy to satisfy as much as 5 to 8 percent of that goal. GreenVolts, a developer of distributed generation photovoltaic (PV) systems, referred to the RETI *Phase 1B Draft Resource Report*, which identifies the potential for 27,500 MW of distributed solar photovoltaic projects rated at 20 MW that could be placed close to existing substations. [29] These projects could generate nearly 60,000 GWh annually, which is significant given that the current estimate of 33 percent of retail sales in 2020 is about 102,000 GWh.

Distributed generation is a key component of the state's loading order for meeting new resource needs.[30] The California Solar Initiative has a target of 3,000 MW of new solar generating systems in the state by 2017.[31] In addition, the Governor's Bioenergy Action Plan calls for meeting 20 percent of the overall RPS target with biopower; all of the current biopower contribution to the RPS and most of the future contribution will come from power plants smaller than 50 MW. Many of these facilities, such as landfill gas generators and digester gas generators, are located in load pockets and can be connected at the distribution level. Further, the *2007 IEPR* recommended that all new residential buildings be net-zero energy by 2020 and all new commercial buildings be net-zero energy by 2030. Distributed generation resources are necessary to achieve this goal.

There is also increasing policy attention to the goal of sustainable communities. More California communities are considering renewable generation options as they explore strategies to become net-zero energy communities. Options include solar PV, solar thermal electric, biogas, and wind power plants in the 10 to 50 MW range. Examples of net-zero communities using renewable energy already exist in California on university campuses and in the operations of regional water agencies.[32] Many California schools are also purchasing renewable electricity from solar electricity systems installed on school roofs.[33]

California Energy Commission, Renewables Portfolio Standard Eligibility Guidebook, January 2008, page 18, http://www.energy.ca.gov/2007publications/CEC-300-2007-006/CEC-300-2007-006-ED3-CMF.PDF.

29 Black and Veatch, *Renewable Energy Transmission Initiative Phase 1B Draft Resource Report*, August 2008, page 1-6, http://www.energy.ca.gov/reti/documents/2008-08-16_PHASE_1B_DRAFT_RESOURCE_REPORT.PDF.

30 As articulated in the State of California *Energy Action Plan*; see http://www.energy.ca.gov/energy_action_plan/.

31 "California Solar Initiative" is often used to refer to all of the various solar incentive programs in the state that are addressed in Senate Bill 1 (Murray, Chapter 132, Statutes of 2006), and includes programs administered by the CPUC, the Energy Commission, and the publicly owned utilities.

32 The University of California at San Diego generates most of its own electricity and cold water for space cooling of campus buildings and is augmenting its natural gas cogeneration combined heat and power (CCHP) capacity with

Widescale use of renewable generation at the distribution level could also reduce some reliability and operational concerns associated with meeting the 33 percent by 2020 goals by reducing overall load, avoiding or deferring transmission system upgrades, and reducing transmission and distribution losses. However, because integrating distribution level and customer-side renewable resources has received much less attention than integrating large central station renewable resources, it will be important to consider how to address distribution level integration of significant amounts of renewable generation. Also, there may be a need for day-ahead and hour-ahead solar and wind forecasting at the distribution level and even the building level and for new market mechanisms to effectively value distributed and customer-side renewables.

Renewable Energy Heating and Cooling

Heating and cooling demands by the industrial, commercial, and residential sectors account for 40 to 50 percent of total global energy use. Around the world, renewable heating and cooling technologies that use solar, biomass, and geothermal resources are used to reduce GHG emissions, electric and natural gas use, and fossil fuel dependency. Current annual GHG emissions in California from space, process, and water heating and cooling in the commercial, residential, and industrial sectors are about 25 percent of total statewide GHG emissions.[34] Using these technologies in California could therefore provide benefits beyond reducing electricity loads.

China accounts for 75 percent of annual solar water heating capacity additions, and Germany has installed the electric equivalent of nearly 5 GW of solar water heaters. In Europe and North America, there are more than 2 million ground source heat pumps in use, with about 30 percent of houses in Sweden having geothermal heat pumps with a combined equivalent electric capacity of nearly 4 GW. The solar share of Germany's residential space heating market is approaching 50 percent, while many countries and state/local jurisdictions are mandating solar water heating for all new residential and commercial buildings.

Although industries offering commercially ready technologies in California are underdeveloped and unprepared to deliver on a large scale, there are programs available to support renewable energy heating and cooling technologies. San Diego Gas & Electric Company (SDG&E) has a Solar Water Heating Pilot Program through December 31, 2009, with $1.5 million for incentives,[35] while the California Solar Initiative has budgeted $100.8 million in

---

solar PV and other renewables (http://ucsdnews.ucsd.edu/thisweek/2008/07/21_sustainable_energy_program.asp). Likewise, the Inland Empire Utility Agency (a regional water agency in San Bernardino County) recently announced the addition of 2MW of PV capacity to its existing 3 MW of bio-power generated from dairy manure and food waste. IEUA is close to serving its total electricity demand for pumping and purification cost-effectively from renewables (www.**ieua**.org/docs/press/2008/PressReleaseSolarProject.pdf)).

33 For example, Chevron Corp. is underway with a 14-site solar power and efficient energy project for the Milpitas Unified School District (http://www.bizjournals.com/sanfrancisco/stories/2008/06/23/daily31.html?ana=from_rss).

34 Meg Waltner, California Alternative Energy and Advanced Transportation Financing Authority.

35 http://www.sdenergy.org/ContentPage.asp?ContentID=409&SectionID=440.

incentives for “non-PV electric displacing solar thermal,” including solar water heating, solar-forced air heating and solar cooling or air conditioning, among other technologies. Specifications for eligible non-PV systems are under development.[36]

The potential value of renewable heating and cooling technologies could be very high, since California residential and commercial cooling accounts for approximately 30 percent of electric system peak load.[37] The National Renewable Energy Laboratory has estimated that 65 percent of residential and 75 percent of commercial buildings in California could be outfitted with solar collectors for hot water. Estimates by the Economic and Technology Advancement Committees suggest that as much as 20 percent of heating- and cooling-related GHG production could be eliminated using low-temperature solar collectors for solar water heating, plus advanced solar thermal collectors suitable for solar cooling and other higher temperature applications. Geothermal heat pumps can cut heating and cooling energy use by 70 percent, which would result in significant additional GHG emission reductions. Solar cooling can provide the added benefit of space cooling that displaces electricity generation needs.

To capture the potential GHG and load-reduction benefits of renewable heating and cooling technologies, California needs to strengthen the market for commercially mature technologies while also targeting research, development, and demonstration efforts for emerging technologies.

Emerging Technologies for Renewables Integration

Energy storage and transmission measurement and information systems can play an important role in helping to integrate renewables. Improvements in wind and solar forecasting and further development of the “smart grid” concept can provide additional benefits. These new technologies and strategies need to be assessed to determine which are appropriate for near-term and long-term implementation, and what efforts should be undertaken to accelerate commercialization of the most promising potential solutions.

A recurring theme in the workshops was the use of the “smart grid” concept to help reduce the impacts of integrating large amounts of renewables into the system. Smart grid uses advanced sensing, communication, and control technologies to improve overall efficiency, reliability, and cost-effectiveness of electrical transmission and distribution system operations, planning, and maintenance. Faster, more reliable, and more capable two-way communications systems will provide new energy management options to all levels of the utility grid system, including generation, transmission, distribution, and customer end use. A smart grid will provide the ability to aggregate end customer loads for demand response, automatically locate utility system outages, quickly resolve utility system congestion issues, automatically control building and industrial loads in response to critical network needs or the ability for all customers to have greater options to manage their energy needs.[38] As California moves to implement a smart grid

---

36 http://www.gosolarcalifornia.ca.gov/documents/CSI_HANDBOOK.PDF, p. 5, 9. See also. CPUC D.06-12-033.

37 http://enduse.lbl.gov/info/LBNL-47992.pdf.

38 The U.S. Energy Independence and Security Act of 2007 identifies the key elements of a “smart grid,” and Title XIII defines many of the capabilities and benefits the nation expects to receive by transitioning to a “smart grid.” The

system, more options will be available to manage and control renewable generation resources connected at the distribution level, as well as to enable the use of demand response measures to help address operational impacts of increased integration of renewables.

Based on discussions and input from the IEPR staff workshop on July 31, 2008, the following emerging technologies appear to have the highest potential to support the integration of renewables:

Energy Storage Technologies: These technologies have significant potential to resolve grid stability and operations issues related to higher penetrations of renewables. Energy storage can be applied as generation, such as pumped hydroelectric storage; on the transmission or distribution system, to regulate fluctuations in generator output and maintain transmission system voltages at required levels; and even at the end-use customer's location. Smaller energy storage systems can provide significant grid support whether they are connected at the distribution or end-use customer level; and aggregating these systems can provide grid support when higher levels of renewables are introduced. Energy storage technologies are advancing rapidly in their system performance, overall capability to address distribution and transmission level problems, and commercial viability. Field demonstrations and pilot projects are needed for larger energy storage systems (greater than 5 MW ratings for at least four hours) that can be connected to the distribution or transmission system. Additional research should evaluate very large energy storage systems, such as compressed air energy storage in comparison to pumped hydroelectric systems currently in use, for situations in which there is a need for storage systems that can store hundreds of MWs for several hours. [39]

High Temperature Thermal Energy Storage for Solar Thermal Electric Plants: Heat produced by a solar power plant collector field can be stored in a mixture of sodium and potassium salts, used to generate steam to produce electricity, and then reheated for reuse. Thermal storage has many potential applications, including increasing the capacity factor of a solar power plant, reducing the need for backup for the variable solar resource, shifting energy delivery to higher value periods, and even boosting energy production during peak periods. Determining the specification for storage applications in California and addressing risks before committing to commercial application in California will increase the economic performance of California's future fleet of solar power plants and allow them to better meet peak summer energy needs.

Increase the Capability of Forecasting Tools: Higher penetration of wind and solar resources requires improved forecasting tools to inform electricity scheduling and dispatch decisions. Accurate forecasts also help address intermittence and unpredictability of resources and can increase the value of variable resources to the system. The California ISO has been using hour-

U.S. Department of Energy is working actively with representatives from all elements of the utility industry to identify the key codes, standards and protocols necessary to implement the "smart grid" of the future. The Energy Commission and the Public Utilities Commission are working together to help the California utilities develop a definition of the "smart grid" of the future that will work for and apply to all of California.

39 Unlike generation equipment ratings that are determined by power generation or electrical efficiency, the performance of energy storage systems is determined by the capacity and duration of the equipment.

ahead forecasting for wind resources successfully for several years but believes that forecasting tools need to be expanded to include day-ahead forecasting and forecasting capability for solar resources.[40] Toward this end, it is doing in-depth studies with three companies to improve wind forecasting ability. Research and development in this area should focus on increasing the accuracy and reliability of forecasts, expanding forecasting tools to encompass solar resources, and working with grid operators to understand their needs in displaying forecast results to allow real-time decisions to be made.

Synchrophasor Measurement Technologies: Phasor Measurement Units[41] can collect and report critical electrical measurements approximately 30 times per second, providing information about grid conditions to system operators so they can make time-sensitive decisions. As more renewable resources are integrated into the grid, operators need this kind of technology to respond to unpredicted changes in output that are characteristic of some renewable technologies. Additional demonstrations and pilot projects are needed along with continued and expanded research in this area.

Transmission Dynamic Thermal Rating Capability: Electricity transmission is limited by the thermal constraints of transmission lines. Resistance of the flow of electrons through transmission lines and equipment produces heat, and overheating can lead to loss of line strength or expansion and permanent sagging of the lines. New technologies can now monitor transmission lines and environmental conditions and calculate real-time line ratings. This allows existing transmission lines to be used to their full capability and reduces the need for new transmission lines. Real-time transmission line ratings could provide more transmission capacity during periods of high system load, decreasing the need to use local generating resources. This could reduce capital expenditures for new transmission facilities and generating resources, while at the same time allow more efficient operation of the power grid, resulting in lower utility rates. The ability to monitor transmission lines in real-time would also improve system reliability and safety.

Addressing Contracting Issues

As of July 2008, the CPUC has approved contracts for nearly 6,000 MW of new and existing RPS-eligible generating capacity.[42] Only about 400 MW of that capacity is currently on-line and delivering energy, while approximately 30 percent of contracts signed since 2002 are either

40 Comments by David Hawkins, July 21, 2008, IEPR workshop, http://www.energy.ca.gov/2008_energypolicy/documents/2008-07-21_workshop/2008-07-21_TRANSCRIPT.PDF, page 124.

41 Devices capable of long-term recording of electrical characteristics and disturbances on transmission grids.

42 California Public Utilities Commission, July 2008, Renewables Portfolio Standard Quarterly Report to the Legislature.

delayed or have been cancelled.[43] There are serious concerns about the reasons for these contract failures and whether this problem may be getting worse.

A related issue with contracts is the small number of biomass contracts that have been signed through RPS solicitations. The Governor's Bioenergy Action Plan sets a target for 20 percent of the state's RPS to be met with biomass.

Renewable contract delays or cancellations continue to be a barrier to meeting California's renewable goals. This issue was raised in both the *2006 IEPR Update* and the *2007 IEPR*, with the *2006 IEPR Update* recommending that utilities procure a contract risk reserve margin of at least 30 percent above what would be needed to achieve the 20 percent by 2010 goal. In written comments for the July 21, 2008, IEPR staff workshop, Green Power Institute echoed this recommendation by noting that if retail providers continue to gear procurement toward getting just enough renewables to meet their requirements, they will not meet the 33 percent mandate because not all signed contracts will result in operating facilities.

In its July 2008 quarterly report to the Legislature on RPS procurement status, the CPUC rated the risk associated with each project's RPS generation and noted that even if all 2010 generation that is now rated medium or high risk or under negotiation were to come on-line by that year, IOUs would still not meet the 20 percent by 2010 target. In that report, the CPUC identified the major risk factors for expected new 2010 RPS generation, with possible expiration of federal Production and Investment Tax Credits and transmission constraints being those affecting the largest percentage of new generation.

At the August 21, 2008, IEPR joint committee workshop, the Independent Energy Producers Association stated that progress toward the state's RPS goals should not be determined based on signed contracts, but rather on projects delivering renewable MWhs to the grid. The association noted that it had filed a motion at the CPUC to investigate RPS procurement processes in California because of its concern that the IOUs are focused on selecting low-cost bidders rather than viable projects.[44]

Although lack of transmission continues to be quoted as a major barrier to the development of new renewable projects, several parties at the IEPR workshops noted that, while RPS bid details and negotiations are confidential, they have heard anecdotally of projects not requiring major transmission upgrades that have not been selected in RPS solicitations. PG&E stated that it has not seen any such projects bidding into its solicitations, while Green Power Institute warned against using transmission access as an excuse for failure to meet current RPS targets or as an argument against setting a 33 percent by 2020 target.

---

43 California Energy Commission, Database of IOU Contracts for Renewable Generation, July 2008 update, www.energy.ca.gov/portfolio/IOU_CONTRACT_DATABASE.XLS.

44 Transcript of the August 21, 2008, IEPR Joint Committee Workshop on Achieving Higher Levels of Renewables in California's Electricity System. Page 168-173, http://www.energy.ca.gov/2008_energypolicy/documents/2008-08-21_workshop/2008-08-21_TRANSCRIPT.PDF.

San Diego Gas & Electric Company submitted written comments for the July 21, 2008, IEPR staff workshop encouraging the Energy Commission to focus its IEPR efforts on determining what the state can do to promote the timely development of projects already under contract. At the August 21, 2008, IEPR joint committee workshop, Abengoa Solar suggested that the Energy Commission meet with project developers to discuss contract delays and analyze why contracts are failing.[45]

Potential Use of Feed-In Tariffs

The *2007 IEPR* recommended that the CPUC should immediately implement a feed-in tariff set initially at the market price referent for all RPS-eligible renewables up to 20 MW and that the Energy Commission should collaborate with the CPUC to develop feed-in tariffs for larger projects.[46]

Feed-in tariffs are essentially standardized contracts to sell energy delivered to the grid at a fixed price – although some feed-in tariffs step down in price over time – which can either be an all-inclusive rate or a fixed premium payment on top of the prevailing spot market price for power. The price paid is based on estimates of either the cost or value of renewable generation. The tariff is generally offered by the interconnecting utility and sets a standing price for each category of eligible renewable generator, with the price available to all eligible generators.

Assembly Bill 1969 (Yee, Chapter 731, Statutes of 2006) authorizes tariffs and standard contracts for the purchase of eligible renewable generation from public water and wastewater facilities. In February 2008, the CPUC made new feed-in tariffs available for the purchase of up to 480 MW of renewable generating capacity from small facilities (up to 1.5 MW) throughout California to provide a simple mechanism for small renewable generators to sell power to the utility at predefined terms and conditions, without contract negotiations.[47]

Assembly Bill 1807 (Fuentes, 2008) was introduced in 2008 to require the Energy Commission to examine the feasibility of feed-in tariffs for renewable facilities larger than 20 MW but did not move forward.

Energy Commission staff held a workshop on June 30, 2008, to discuss the challenges and opportunities associated with using feed-in tariffs to increase renewable generation in California. At that workshop, staff presented a consultant report by KEMA, Inc., on feed-in tariffs to stimulate discussion and provide a primer on the issues surrounding the use of feed-in

---

45 Transcript of the August 21, 2008, IEPR Joint Committee Workshop on Achieving Higher Levels of Renewables in California's Electricity System. Page 188 Line 3-20. http://www.energy.ca.gov/2008_energypolicy/documents/2008-08-21_workshop/2008-08-21_TRANSCRIPT.PDF.

46 The market price referent is set by the CPUC and estimates market costs for a fixed-price, long-term contract for electricity generated from a new natural gas facility. California Public Utilities Commission, Resolution E – 4118, Resolution formally adopting the 2007 Market Price Referent for use in the 2007 Renewables Portfolio Standard solicitations, October 4, 2007

47 California Public Utilities Commission, http://www.cpuc.ca.gov/PUC/energy/electric/RenewableEnergy/feedintariffssum.htm.

tariffs.[48] Further workshops are scheduled in October and November with plans to publish a final report by the end of 2008.

The issue of feed-in tariffs also arose during the IEPR workshops. At the July 21, 2008, workshop, the Center for Resource Solutions discussed feed-in tariffs as a way to complement existing RPS procurement by providing another opportunity for large-scale (greater than 20 MW) renewable energy development projects that have transmission access, site control, and permitting to obtain RPS contracts. However, the California ISO stated that RPS procurement and contracting is not the main barrier to renewable development, but rather transmission, permitting, and siting are the key issues. The CPUC agreed that procurement is not the problem, but stated that perhaps feed-in tariffs could play a role in increasing the amount of renewables in the state.

During the August 21, 2008, workshop, PG&E said that unless permitting, availability of the federal investment tax credit and production tax credit, and transmission are addressed, a feed-in tariff would not result in more renewable energy than the current approach to RPS procurement. PG&E noted that feed-in tariffs in Germany are much higher than California's market price referent set by the CPUC and said that if IOUs were required to pay an administratively set price higher than the price they can negotiate (which appears to be equal or close to the market price referent), the increased payment to the developers would represent a lost value to consumers and increased profit to suppliers.[49] However, feed-in tariffs reduce uncertainty and allow developers to obtain lower-cost financing and to be less vulnerable to costs related to delays in permitting, siting, interconnection, and equipment procurement.[50]

GreenVolts, a developer of distributed generation PV systems, discussed the benefits and large potential for PV less than 20 MW located near load[51] and believes that a feed-in tariff can energize the wholesale distributed generation market segment. To unlock this potential, they suggested a feed-in tariff for projects 20 MW and below that would be based on the market price referent, plus time-of-use and locational benefits for generating close to load.[52]

---

48 KEMA, Inc., *Exploring Feed-In Tariffs for California*, June 2008, http://www.energy.ca.gov/2008publications/CEC-300-2008-003/CEC-300-2008-003-D.PDF.

49 Transcript of the August 21, 2008, IEPR Joint Committee Workshop on Achieving Higher Levels of Renewables in California's Electricity System. Page 140-142. http://www.energy.ca.gov/2008_energypolicy/documents/2008-08-21_workshop/2008-08-21_TRANSCRIPT.PDF.

50 For more information, see KEMA, Inc., September 2008 (forthcoming), *California Feed-in Tariff Design and Policy Options, Draft Consultant Report*., prepared for the California Energy Commission.

51 Renewable Energy Transmission Initiative *Phase 1B – Draft Resource Report*. August 16, 2008. Page 6-8. http://www.energy.ca.gov/reti/documents/2008-08-16_PHASE_1B_DRAFT_RESOURCE_REPORT.PDF

52 Transcript of the August 21, 2008, IEPR Joint Committee Workshop on Achieving Higher Levels of Renewables in California's Electricity System. Page 186 Line 2-8. http://www.energy.ca.gov/2008_energypolicy/documents/2008-08-21_workshop/2008-08-21_TRANSCRIPT.PDF.

Addressing Price Impacts

A continuing concern among parties is the potential for higher electricity costs as a result of moving to 33 percent renewables. Forecasts of electricity rates are very uncertain and depend on a number of variables such as future natural gas prices, costs associated with potential carbon regulation, the cost of necessary upgrades to the transmission and distribution grids, capital costs of building new facilities, and the cost of generation.

Natural gas prices remain high and volatile, and prices over the long term will depend on the impacts of uncertain technological, economic, and political factors. Future costs of carbon regulation are unknown, but the *2007 IEPR* noted that, according to the Intergovernmental Panel on Climate Change, carbon prices could be as high as $100 per ton by 2030.[53] Construction costs for all generation resources continue to rise, with some estimates that the cost of building a natural gas power plant in the United States has increased by 92 percent since 2000.[54] Regarding the cost of new transmission investment, the *2007 IEPR* noted that investment will be needed to maintain system reliability and serve increasing electricity demand in any case, even if the state were not committed to 33 percent renewable generation by 2020.

In evaluating the impacts of higher levels of renewable penetration in California, cost assumptions will need to be made about renewable generation resources. The CPUC's 33 percent RPS implementation analysis will be evaluating statewide cost and rate impacts, relying on RETI cost estimates as much as possible, and the Energy Commission will need to consider the conclusions from that study and from the RETI efforts in any cost evaluations.

However, in evaluating price impacts, it is important to remember the goals of increasing renewable generation, which include reducing dependence on natural gas as well as reducing GHG emissions. The potential costs associated with not meeting those goals, including higher electricity rates resulting from high natural gas prices as well as the economic effects of catastrophic climate change, must be considered in any evaluation of the costs of moving to higher levels of renewables.

Parties at the IEPR workshops noted that price impacts are an important issue but that future costs are extremely uncertain. SCE noted that the Energy Commission's *2007 IEPR Scenario Analysis Project* was a good beginning, but that actual price data is different from the assumptions used in that analysis, and believes that wholesale costs to all purchasers of power

---

53 The Intergovernmental Panel on Climate Change reports a 445–490 parts per million CO_2 equivalent as substantially reducing the expected magnitude, impact, and rate of climate change from business-as-usual scenarios by 2050 from 2000 emission levels and states that most individual studies for this category of reductions cluster around $100 per ton CO_2 by 2030. Intergovernmental Panel on Climate Change, 2007, *Climate Change 2007: Mitigation*. Contribution of Working Group III to the *Fourth Assessment Report of the Intergovernmental Panel on Climate Change*. Metz, B., O. R. Davidson, P. R. Bosch, R. Dave, and L. A. Meyer (eds). Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. <www.ipcc.ch/pdf/assessment-report/ar4/wg3/ar4-wg3-chapter3.pdf>, p. 198, Table 3.5 and p. 206.

54 IHS CERA Power Capital Costs Index, http://energy.ihs.com/News/Press-Releases/2008/IHS-CERA-Power-Capital-Costs-Index.htm.

will increase by implementing a 33 percent goal.[55] Green Power Institute noted that because there is little doubt overall energy costs will increase in the future with the phasing out of fossil fuels, it may not matter if implementing the 33 percent target increases wholesale energy costs in and of itself given the importance of achieving that target to meet California's GHG reduction goals.[56]

Natural Gas Price Links to Renewable Energy

NYMEX natural gas futures have fluctuated greatly in the past 12 months, from about $6 per million British Thermal Units (MMBtu) to a peak of more than $13 per MMBtu.[57] In California, prices for renewable energy are linked to natural gas prices through the benchmark market price referent used in the RPS procurement process, which estimates market costs for a fixed-price, long-term contract for electricity generated from a new natural gas facility.

The IEPR workshop on July 21, 2008, summarized the findings from several studies on the potential effects of high levels of renewables on natural gas demand and prices. Lawrence Berkeley National Lab reviewed 13 studies of potential federal RPS programs ranging from 7.5 percent to 20 percent renewables and concluded that most studies showed net savings of $7 to $20 per MWh on electricity and natural gas bills across the United States. They also estimated changes in natural gas demand in California if IOUs met the 33 percent goal, and found that demand for natural gas could drop about 1 percent per year from 2011 to 2020, reaching about 9 percent below 2010 levels. This reduced demand could result in substantial natural gas savings (and associated CO_2 reductions) for California from 2011 through 2030, with the estimated net present value of natural gas savings in 2011 dollars between $0.8 billion and $2.0 billion.[58]

A 2005 report by the Center for Resource Solutions on achieving a 33 percent renewable energy target used the Lawrence Berkeley National Laboratory analysis to estimate natural gas price suppression effects and concluded that the incremental value of moving from 20 percent to 33 percent renewables in displacing natural gas can be from $3.5/MWh to $8.5/MWh.[59]

---

55 Public Comments – Staff Workshop: Impacts of Higher Levels of Renewables on the Electricity System – Summary of Recent Studies. August 1, 2008, http://www.energy.ca.gov/2008_energypolicy/documents/2008-07-21_workshop/comments/TN%2047436%20Comments%20of%20SCE%20on%20Questions%20attached%20to%20Staff%20Workshop%20Notice.pdf.

56 Written comments by Green Power Institute submitted for the July 21, 2008, IEPR workshop, July 31, 2008, http://www.energy.ca.gov/2008_energypolicy/documents/2008-07-21_workshop/comments/TN_47448_Green_Power_Institutes_Comments_on_Staff_Workshop.pdf.

57 NYMEX Natural Gas Futures Close (Front Month), http://www.wtrg.com/daily/ngfclose.gif, accessed August 4, 2008.

58 Wiser, Ryan and Mark Bolinger, 2005, Can Deployment of Renewable Energy and Energy Efficiency Put Downward Pressure on Natural Gas Prices?, http://repositories.cdlib.org/lbnl/LBNL-57270/.

59 California Public Utilities Commission, Nov 2005, *Achieving a 33% Renewable Energy Target*, prepared by Center for Resource Solutions (CRS) for the CPUC, http://www.resource-solutions.org/lib/librarypdfs/Achieving_33_Percent_RPS_Report.pdf .

The 2007 Scenario Analysis Project conducted as part of the *2007 IEPR* also looked at the natural gas use and price impacts of increased levels of renewables. Based on a westwide scenario that included high efficiency, high renewable, and rooftop PV, the study indicated large reductions in gas use for electricity generation and price reductions in the range of 50 cents to $1 per MMBtu. The study, however, did not reflect likely behavioral changes from gas producers in response to reduced gas demand, such as reduced long-term capital investments. To incorporate those changes, staff ran the GPCM® model[60] and came up with expected price reductions of 10-25 cents per MMBtu.[61] Given the unproven assessment methods in the study, the *2007 IEPR* noted the existence of this natural price reduction effect, but said it could not be quantified well enough to be reliable.[62]

Several parties at the IEPR workshops noted that California may not see significant reductions in natural gas demand or price because of rising demand in other states as they move from coal to natural gas resources in response to GHG concerns. With the evolving global nature of natural gas markets, increased U.S. demand could offset any demand or price reductions in California from displacing natural gas resources with renewable resources.

The California ISO also stated that the need to back up variable wind renewable resources with natural gas plants may be exporting that variability to the natural gas system. Because variable resources like wind fluctuate in response to weather conditions, natural gas plants need to respond quickly to those variations, with associated impacts on the natural gas transmission and storage systems. In addition, it is unclear how to communicate the need for these rapid changes in supply to the gas pipeline companies.[63]

Clearly, there is a need for further evaluation of the links between natural gas demand and price and the increased use of renewable resources. Evaluation of this issue could include an examination of the regional price impacts from changes in natural gas demand and supply opportunities. Also, it will be necessary to better understand physical changes to natural gas supply, delivery, and storage systems to support a 33 percent renewable energy future. There may be a requirement for new natural gas transport capability to California and additional

---

60 GPCM® is RBAC's Natural Gas Market Forecasting System, originally known as the Gas Pipeline Competition Model, which is a combination software-database system to enable users to build models for analysis of natural gas economics.

61 Transcript of the July 21, 2008, IEPR Staff Workshop on Impacts of Higher Levels of Renewables on the Electricity System: Summary of Recent Studies. Page 28-44. http://www.energy.ca.gov/2008_energypolicy/documents/2008-07-21_workshop/2008-07-21_TRANSCRIPT.PDF

62 Presentation Prepared for California Energy Commission by Altos Management Partners. August 16, 2007. http://www.energy.ca.gov/2007_energypolicy/documents/2007-08-16_workshop/presentations/Dale_Nesbitt_Altos_Management.pdf

63 Transcript of the July 21, 2008, IEPR Staff Workshop on Impacts of Higher Levels of Renewables on the Electricity System, comments by Dave Hawkins, California Independent System Operator, page 134, http://www.energy.ca.gov/2008_energypolicy/documents/2008-07-21_workshop/2008-07-21_TRANSCRIPT.PDF.

storage to support the cycling of natural gas-fired generation to back up intermittent renewable energy resources.

In addition, there is a need for continued evaluation of how feed-in tariffs could be used to decouple the price paid for renewable energy from the price of natural gas by focusing on the actual cost of generation of renewable resources.

Cost of Generation

The *2007 IEPR* recommended that the Energy Commission refine the input data used in its Cost of Generation Model in the *2009 IEPR* and establish a process to regularly update changing technology costs over time. [64] Because of the increasing role that newer technologies, particularly renewable technologies, are likely to play in the future, it is important that cost assumptions used in the various analyses on the effects of higher levels of renewables accurately reflect potential price changes for both conventional and renewable resources that may occur in the next decade.

Addressing Environmental Issues

Environmental permitting of large-scale renewable power plants is an increasing concern given the number and size of proposed plants and the areas of the state in which they will be located. The Energy Commission has received applications for nearly 1,700 MW of new solar facilities. Another 1,100 MW of new facilities have been announced but not yet applied. The federal BLM has received applications for solar and wind facilities on public lands totaling about 1.3 million acres. [65]

There are several efforts underway related to the environmental permitting of renewable power in California. The U.S. Department of Energy (DOE) and the BLM are jointly preparing a solar energy programmatic environmental impact statement as a prelude to permitting or sponsoring large-scale solar electricity-generating installations in the western United States, including the Southern California desert. The BLM and DOE are evaluating whether installations of large-scale solar electric power plants on public lands could be facilitated by developing agency-specific programs that establish environmental policies and mitigation strategies for this solar development. In addition, the BLM and the Energy Commission have entered into a Memorandum of Understanding to more efficiently evaluate the environmental impacts of solar thermal projects above 50 MW in California by avoiding duplication of staff efforts, sharing staff expertise and information, and allowing public review by providing a joint environmental document.

---

64 California Energy Commission, *Comparative Costs of California Central Station Electricity Generation Technologies,* December 2007, CEC-200-2007-011-SF, provides a description of the Cost of Generation Model, summarizes the calculated levelized costs, and provides the supporting data and a description of how that data was collected and processed.

65 Testimony of Bob Doyel, Bureau of Land Management, July 23, 2008, Integrated Energy Policy Report staff workshop on transmission issues, page 89, http://www.energy.ca.gov/2008_energypolicy/documents/2008-07-23_workshop/2008-07-23_TRANSCRIPT.PDF

An associated effort is the RETI, which is identifying competitive renewable energy zones in California and neighboring states that can provide significant electricity to California consumers by 2020. RETI will identify zones that can be developed in the most cost-effective and environmentally benign manner.

Much of the land where new renewable facilities will be located is ecologically sensitive and may require significant habitat mitigation. Solar facilities in particular require large amounts of land, and identifying enough ecologically appropriate land elsewhere to reduce potential impacts will be a challenge. At the IEPR joint committee workshop on August 21, 2008, the representative for BrightSource Energy, a developer of large-scale solar, suggested that clear information is needed on what constitutes adequate mitigation, recognizing that some locations are more ecologically valuable than others. Because the cost of mitigation and restoration must be factored into project finances, more information on these costs would assist developers.[66]

In written comments submitted for the IEPR staff workshop on July 23, 2008, the Alliance for Responsible Energy Policy stated that California's rush to identify competitive renewable energy zones and to permit new transmission lines has failed to adequately consider distributed generation and demand-side management alternatives.[67]

Recommendations

Analysis Needed in 2009 Integrated Energy Policy Report

- The *2009 IEPR* should include a thorough evaluation of the issues required to transition to a higher renewables future, and how other key issues, such as once-through cooling, aging power plant retirements, and GHG reductions are affected.

Transmission Barriers

- The state should identify and implement ways to remove barriers to joint publicly owned utility and investor-owned utility transmission projects, including:
    - The Energy Commission should work collaboratively with IOUs and publicly owned utilities in the RETI Phase 2 activity to develop conceptual transmission plans that will inform the *2009 IEPR/Strategic Transmission Investment Plan* process and provide information on potential high-priority transmission projects and corridors that may be necessary in the future to help achieve higher levels of renewables penetration. The RETI Phase 2 results, together with information on planned transmission projects and corridor needs that will be collected through the *2009 IEPR* process, will help identify opportunities for joint project collaboration.

---

66 Transcript of the August 21, 2008, IEPR Joint Committee Workshop on Achieving Higher Levels of Renewables in California's Electricity System. Page 200-211. http://www.energy.ca.gov/2008_energypolicy/documents/2008-08-21_workshop/2008-08-21_TRANSCRIPT.PDF

67 Alliance for Responsible Energy Policy, written comments submitted for the July 23, 2008, Integrated Energy Policy Report Update workshop, http://www.energy.ca.gov/2008_energypolicy/documents/2008-07-23_workshop/comments/TN%2047164%20Alliance_for_Responsible_Energy_Policy.pdf.

- To promote joint transmission project opportunities, the Energy Commission should use the *2009 IEPR* and *2009 Strategic Transmission Investment Plan* processes as forums to identify and evaluate regulatory or policy changes that would reduce both legal and market obstacles to joint projects development

- The Energy Commission should work closely with stakeholders in the development of RETI Phase 2 conceptual transmission projects to ensure that land use issues and environmental concerns are evaluated and considered. To inform and build greater public support for achieving the state's renewable and greenhouse gas reduction goals, as well as the crucial role transmission projects play in providing access to renewable resources, the Energy Commission recommends restoring funding to the Energy Commission's local assistance program established under Public Resources Code section 25616. This program can be used to assist local governments with the development of general plan energy elements that recognize the importance of these statewide goals.

Integration Issues

- Transmission conceptual plans must consider new operational issues such as the effects of accelerated shutdown of existing in-basin generation, which would adversely affect grid operability and deliverability concerns. In addition, the state should continue to implement the key recommendations made by CERTS/EPG in its renewable resource integration work done for the Energy Commission, such as improved, long-term, and integrated transmission planning.

- Load-serving entities' procurement plans should demonstrate how their anticipated renewable, non-renewable, demand response, and storage resource mix will address local capacity requirements to maintain system reliability.

- The state should ensure sufficient funding for research and development efforts on:

  - Identifying the energy storage technologies with the most promise to resolve grid stability and operations issues related to higher penetrations of renewables, reduce the costs of those technologies, and increase their commercialization.

  - Identifying, developing, and integrating transmission system improvements and technologies that can increase and control bulk power flows on the transmission system, provide real-time information to transmission operators to allow optimization of the existing transmission system, and diminish local capacity requirements in load pockets.

  - Expanding efforts on renewable integration issues to include distribution-level and building-integrated renewables and analyzing the costs and benefits of installing 20 MW solar PV facilities at suitable distribution substations.

  - Developing a targeted program for emerging renewable heating and cooling technologies and assessing how to strengthen the market for commercially mature technologies.

- Transmission-related research, development, and demonstration activities needed to facilitate renewables integration will require a significant increase in research and development spending by the state. The CPUC and the Energy Commission should investigate potential sources of funding beyond what is already committed to such efforts such that transmission-related research and development are funded at no less than $60 million per year. In addition, the Legislature should require publicly owned utilities to expand their transmission research and development activities as well.

Contracting Issues

- The CPUC must take control of the procurement process for new renewable resources and conduct its own evaluation of proposals based upon cost criteria, as well as likely project success, locational benefits, and land use and environmental considerations, without the direct participation of the IOUs. Other non-market participants and the Energy Commission should assist.

- There continues to be a need for greater transparency regarding signed RPS contracts. The IEPR Committee recommends that IOUs be required to provide aggregated information on contract prices, project locations, and schedules to assure policy makers that RPS contracts are providing the greatest strategic and economic value to the state. In addition, the CPUC should make public the aggregate amount of above-market funds being allocated to RPS contracts.

- The Energy Commission and CPUC should work collaboratively to develop a pilot program to provide feed-in tariffs for renewable projects larger than 20 MW based on the results in the collaborative evaluation and options report on feed-in tariffs that will be completed by the end of 2008.

Price Impacts

- The Energy Commission should evaluate the price and technical impacts of increased use of renewable resources on natural gas demand and price as well as the impacts of regional changes in natural gas supply and demand on California demand and prices.

- The Energy Commission should evaluate the availability of natural gas in California based upon different scenarios and increasing worldwide demand.

- The Energy Commission should continue its efforts to refine the input data in its Cost of Generation Model and focus on regularly updating changing technology costs over time.

- Along with the CPUC's 33 percent RPS evaluation, the Energy Commission should estimate potential price impacts of the 33 percent RPS target based on current contracts and scenarios using the Cost of Generation model

Environmental Issues

- The Energy Commission should continue to work with the RETI Environmental Working Group to identify competitive renewable resource zones where renewable energy development is expected to be least damaging to the environment.

- The Energy Commission should continue its participation in the Solar Programmatic Environmental Impact Statement (PEIS) efforts with DOE and the BLM and continue to work with the BLM to evaluate the environmental impacts associated with permitting solar thermal facilities in California.

- The CPUC should include land use and environmental considerations in selection of RPS contracts with assistance from the Energy Commission.

CHAPTER 2: Energy Efficiency and Demand Forecasting

Introduction

With the state's adoption of the first *Energy Action Plan* in 2003, energy efficiency became the resource of first choice for meeting the state's future energy needs. Assembly Bill 2021(Levine, Chapter 734, Statutes of 2006) set a statewide goal of reducing total forecasted electricity consumption by 10 percent over the next 10 years. Under AB 2021, the Energy Commission, along with the CPUC, is responsible for setting annual statewide efficiency targets in a public process using the most recent IOU and publicly owned utility targets. These targets, combined California's greenhouse gas emission reduction goals, make it essential for the Energy Commission to properly account for energy efficiency impacts when forecasting future electricity and natural gas demand.

This chapter discusses the challenges involved in measuring and attributing energy efficiency programs[68] and other market impacts within the Energy Commission's California Energy Demand Forecast process. It also provides an overview of methods currently used by Energy Commission staff to incorporate energy efficiency programs into the forecast. The chapter then details the approach staff will employ to better delineate the efficiency assumptions in the demand forecast within the *2009 IEPR* cycle and beyond as recommended in the *2007 IEPR*. Finally, the chapter reports on progress made by California utilities in fulfilling the efficiency requirements of Assembly Bill 2021.

In forecasting future energy demand, isolating the effects of different sources of savings is a complex process that is sometimes subjective and, therefore, dependent on staff judgment. Utilities and other stakeholders expressed concern during the *2007 IEPR* process about the lack of transparency in staff methods. In particular, parties requested clarification of how much uncommitted savings — savings from efficiency programs reasonably expected to occur but not yet implemented or funded — are accounted for in the forecast. Prompted by these concerns, the *2007 IEPR* committed the Energy Commission in 2008 and beyond to examining the methods used to incorporate efficiency in the Commission's demand forecast in a public process that includes the CPUC staff, utilities, and other stakeholders.

In its scoping order for the *2008 IEPR Update,* the IEPR Committee directed the Energy Commission staff to:

- Clearly explain how energy efficiency is incorporated in the demand forecast, allowing parties to understand how the models include utility programs, standards, and other efficiency codes as inputs when developing the demand forecast.
- Evaluate price response, market effects, and trends in the market, and how they are included or excluded from the demand forecast models.

68 In this context, "efficiency programs" refer to both programs and building and appliance standards.

- Clarify the amount of efficiency program savings or potential embodied in the forecast and how it will affect decisions to go forward with additional efficiency programs.
- Evaluate potential new project capabilities to use along with the demand forecast to examine long-term alternative energy efficiency strategies, such as zero-emission building goals, in support of long-term greenhouse gas reduction goals.
- Identify what collaboration is needed or desirable among utilities, the CPUC, the Energy Commission, and others to refine demand forecasting methods and create needed energy efficiency projection capabilities.

Measurement and Attribution Challenges

Energy efficiency poses major challenges for energy forecasters. It is difficult to reliably estimate reduced consumption from efficiency measures for the following reasons:

- Efficiency results depend inherently upon consumer behavior, which alters with changes in energy prices, cultural practices, and technology. Changes in consumer behavior over time alter the savings that result from energy efficiency measures in ways that are difficult to forecast.
- There are different ways to account for the impacts of efficiency programs taken in isolation, all of which are subject to uncertainty. Results from each method, even if considered reliable, may not directly translate into observable reduced demand due to simultaneous changes in technology and behavior.
- The effects of efficiency efforts depend on variations in program funding and authorization through time that cumulatively may have differential impacts as large as one or more large power plants.

With a generation facility, it is not difficult to accurately determine the amount of power generated at any given time. This is not the case for power saved through efficiency measures. Forecasters estimate demand reductions from efficiency programs relative to what would have happened if those programs were not in place. However, because there is overlap with and spillover effects from other program activities, voluntary actions, and market changes not directly attributable to those programs, it is inherently difficult to determine the amount of reduced consumption that results from a specific program or standard. Energy forecasters must often discount the savings from efficiency programs, or allocate the savings among a variety of programs and market effects, when attempting to accurately predict what amount of energy will be needed. Forecasters do this when programs are not realizing expected savings or to avoid double-counting effects that are not clearly attributable to either programs or other market forces.

It is imperative that energy forecasters and program analysts refine and improve methods to quantify energy efficiency and conservation impacts to yield reliable results, while also accounting for processes already at work in the market.

Another challenge is in developing consistent measurement techniques. The Energy Commission's demand forecast models and utility forecast models use different quantification methods than energy efficiency potential forecasts and models, such as Itron's Asset model,[69] when measuring the impacts of voluntary conservation and efficiency programs. Assumptions also differ about the impact of price and other market effects. Sorting out these differences will require an increasing level of cooperation among the various interested parties.

Incorporating Efficiency in the Demand Forecast

The Energy Commission's demand forecast attempts to account for savings from committed efficiency programs, defined as programs that are either implemented or have approved funding, as well as savings resulting from market effects such as energy price increases.[70] Efficiency programs incorporated in the demand forecast fall into three broad categories: building standards, appliance standards, and utility and public agency programs.

Committed efficiency programs are explicitly incorporated in the Residential Energy Demand Forecast Model, the Commercial Building Energy Demand Forecast Model, and the Energy Demand Summary Forecast Model,[71] but not in the models used for other sectors. The models used for the industrial, agricultural, transportation, communications and utilities, and street lighting sectors do not integrate specific programs but do reflect past efficiency impacts because the models are calibrated to historical energy use.[72]

In the residential and commercial models, efficiency programs are accounted for by changing average energy consumption inputs at the end-use level for each "vintage" of standards and efficiency programs. For the summary model, program impacts that could not be modeled at the end-use level are estimated directly outside the model and then subtracted from aggregated total consumption. Table 1 lists the efficiency programs explicitly incorporated in these three models. The source provided at the bottom of the table gives information on the individual programs.

Staff forecasters attribute savings effects in the residential and commercial sectors by removing efficiency programs in reverse chronological order. The end-use level changes that reflect the most recent adopted standards and funded efficiency programs are removed first, and model runs with these assumptions provide the projected impacts of these standards and programs (and so on). This time-sequencing approach requires a series of model runs, with the end-use modeling of programs removed one at a time in the residential and commercial models. The incremental changes in output between model runs reflect the savings attributable to individual

---

69 The Itron Asset Model, discussed later in this chapter, specifically measures demand-side management program savings, incorporating measure costs and benefits over time.

70 "Other" market impacts include changes to average energy consumption for an end use that are not directly the result of an efficiency program, such as a more efficient technology adopted for cost reasons.

71 The summary model combines the forecast for the individual sectors.

72 In these sectors, staff forecasts are similar to the aggregated econometric forecasts prepared by the utilities.

efficiency programs. Once all efficiency programs are removed, only market impacts remain. Measuring market impacts requires holding electricity prices constant at base year (1977) levels and in some cases estimating the impacts of natural technological change (as in the industrial sector).

Table 1 – Efficiency Programs Explicitly Incorporated in the *2007 IEPR* Forecast

Residential Model	
1975 HCD Building Standards	1988 Federal Appliance Standards
1978 Title 24 Residential Building Standards	1990 Federal Appliance Standards
1983 Title 24 Residential Building Standards	1992 Federal Appliance Standards
1991 Title 24 Residential Building Standards	OII-42 Solar Subsidies
2005 Title 24 Residential Building Standards	Pool Pump Timers
1976-82 Title 20 Appliance Standards	Miscellaneous Retrofit
1984 Title 20 Appliance Standards	
Commercial Model	
1978 Title 24 Nonresidential Building Standards	1998 Title 24 Nonresidential Building Standards
1978 Title 20 Equipment Standards	2001 Title 24 Nonresidential Building Standards
1984 Title 24 Nonresidential Building Standards	2004 Title 20 Equipment Standards
1984 Title 20 Nonresidential Equipment Standards	2005 Title 24 Nonresidential Building Standards
1985-88 Title 24 Nonresidential Building Standards	Federal Schools and Hospitals Program
1992 Title 24 Nonresidential Building Standards	
Summary Model	
Residential New Construction	Energy Extension Service
Residential Master Meter	Miscellaneous Commercial Retrofit
Commercial New Construction	

Source: California Energy Commission, *Energy Demand Forecast Method Report*, CEC-400-2005-036, June 2005.

Table 2 shows the impact of committed efficiency programs, along with price and other market effects, on residential and commercial electricity use for the five major California utilities — Pacific Gas and Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), Sacramento Municipal Utility District (SMUD), and Los Angeles Department of Water and Power (LADWP) — from the *2007 IEPR* demand forecast.

Table 2 also shows historical and projected residential and commercial electricity use from the *2007 IEPR* forecast, as well as historical and projected "unmanaged" use, that is, estimated use in the absence of these savings impacts. The last column shows the percentage reduction in use attributed to the impacts of efficiency programs plus market effects, calculated by dividing total savings by unmanaged use. The "Total Savings" column represents the amount of conservation and efficiency savings explicitly accounted for in the demand forecast. [73]

The total savings shown in Table 2 cannot be compared directly to the statewide goals for all cost-effective energy efficiency because the forecast includes only savings from committed efficiency programs through 2008. In addition, the table only reflects savings from the state's three investor-owned utilities plus the two largest publicly owned utilities, while the AB 2021 goals are statewide.

Table 2 – Residential Plus Commercial Electricity Savings From the *2007 IEPR* Forecast: Five Major California Utilities Combined

Year	Building and Appliance Standards	Utility and Public Agency Programs	**Total Efficiency Program Savings**	Price and Other Market Effects	**Total Savings**	Elec. Use 2007 Adopted Forecast	Elec. Use 2007 Unmanaged Forecast	**Percent Reduction in Use from Savings**
Residential plus Commercial Consumption Impacts (GWH)								
1990	8,218	1,538	**9,755**	12,000	**21,755**	135,746	157,501	**13.8**
2000	18,068	2,920	**20,988**	8,273	**29,261**	169,421	198,682	**14.7**
2005	23,767	3,684	**27,451**	14,404	**41,855**	179,016	220,871	**18.9**
2008	27,486	3,770	**31,255**	16,198	**47,453**	193,233	240,686	**19.7**
2013	33,915	3,552	**37,467**	17,975	**55,442**	210,500	265,942	**20.8**
2018	40,410	3,379	**43,789**	19,381	**63,170**	226,616	289,786	**21.8**
Residential plus Commercial Coincident Peak Impacts (MW)								
1990	2,695	483	**3,178**	2,760	**5,938**	31,447	37,385	**15.9**
2000	5,190	811	**6,001**	1,903	**7,904**	38,320	46,223	**17.1**
2005	6,656	1,000	**7,656**	3,313	**10,968**	42,326	53,294	**20.6**
2008	7,527	1,009	**8,536**	3,725	**12,261**	45,557	57,818	**21.2**
2013	9,039	935	**9,974**	4,134	**14,108**	49,535	63,643	**22.2**
2018	10,607	878	**11,486**	4,458	**15,943**	53,485	69,428	**23.0**

Source: *California Energy Demand 2008-2018 Staff Revised Forecast*, CEC-200-2007-015-SF2, November 2007, various tables.

---

73 The California Air Resources Board Draft Scoping Plan for GHG reductions recommends a statewide efficiency target of 32,000 GWhs in demand reductions relative to business as usual projections for 2020. This target would be in addition to the savings incorporated in the Energy Commission's forecast. See http://www.arb.ca.gov/cc/scopingplan/document/draftscopingplanappendices.pdf, p. C-59.

The decrease in utility and public agency program savings after 2008 shown in the table reflects staff's practice of including committed programs only, so that savings impacts decay as individual programs expire and measure effectiveness diminishes over time. On the other hand, the impacts from standards increase over the forecast period; savings accumulate as new and replacement buildings, appliances, and equipment incorporate these required efficiency levels. These differences in forecast model results come from the nature of the commitment for a standard versus a program. A standard affects all applicable equipment purchased from the effective date going forward until superseded. If the standard is in effect long enough, it may still govern efficiency requirements when replacement appliances are purchased. A utility program is typically authorized conditionally for a finite period or until a budget is exhausted. Thus, a standard's effect grows through time, perhaps for many years, while a utility program's impact gradually diminishes once funding stops.

In addition to electricity savings, natural gas efficiency programs and market effects in the residential and commercial sectors served by the three major California gas utilities (SDG&E, PG&E, and Southern California Gas) saved an estimated 4,337 million therms in 2005, increasing to an expected 5,716 million therms by 2018. Efficiency programs are estimated to contribute roughly 90 percent of savings impacts in both years. These savings are larger relative to total consumption than in the electricity sector; total gas consumption is estimated to be 6,695 million therms in 2005, increasing to 7,768 million therms by 2018. [74]

Future standards and unfunded efficiency programs are not explicitly included in the Energy Commission's demand forecasts. However, this does not imply that independent estimates of savings from these prospective standards and programs can simply be subtracted from the demand forecasts. These estimates may not account for the effect of underlying market and price effects, which can induce some of the savings estimated from individual measures even in the absence of a program or standard. Some of these market and price effects are, in fact, included in the underlying Energy Commission demand forecasts, as shown above, and these should be subtracted from gross estimates of future program and standards impacts before analyses that use the demand forecasts for procurement requirements, greenhouse gas modeling, or other electricity system examinations.

It is clear, however, that the market and price effects included in a vintage of Energy Commission demand forecasts do not vary as more or less aggressive goals for future programs and standards are examined. Differential amounts of future program funding, differing future program designs, and differing stringency of proposed future efficiency standards cannot change the amount of market and price effects included in the demand forecast. Hence, a method that adjusts for impacts already in the demand forecast using a percentage reduction of expected program savings appears inappropriate and will be accurate only for a single projected funding level, stringency level, and/or program design. Given the adopted demand forecast, the most appropriate reduction in near-term analyses of future program and standards effects to reflect the market impacts already incorporated in the forecast is to subtract the

74 California Energy Demand 2008-2018 Staff Revised Forecast, CEC-200-2007-015-SF2, November 2007.

quantified market and price effects identified in Table 2. As this issue is further analyzed in the *2009 IEPR*, this conclusion may be adjusted, but this process should identify a quantity that is subtracted from subsequent program analyses, rather than a percentage reduction.

The Energy Commission's mandate to include energy savings reasonably expected to occur in its planning also includes impacts from uncommitted efficiency programs, that is, not implemented or funded. Staff currently treat impacts from uncommitted programs as being incremental to the demand forecast. During the 2006 CPUC Long-Term Procurement Planning and the *2007 IEPR* proceedings, SDG&E, PG&E, and SCE raised concerns about treating savings from uncommitted programs as being in addition to the Energy Commission's demand forecast. The utilities claimed some estimated uncommitted savings were already included in the Energy Commission forecast, and subtracting all of the impacts as though they were incremental would constitute double counting. Such double counting could occur for various reasons, for example:

- CPUC goal setting may allow proposed program savings to overlap with impacts from the Energy Commission's building standards or federal appliance standards.
- In meeting CPUC goals, IOUs can spend future efficiency program funds to replace expired measures, while the Energy Commission's forecast assumes in some cases savings from the measure would continue without the inducement of any program, assigning the savings to market effects.
- CPUC goal setting may not account for various efficiency improvements from future market or price impacts included in the Energy Commission's forecast.
- Net-to-gross adjustments[75] and program measure life used in determining *ex ante* program impacts in CPUC goal setting are not always consistent with assumptions used in the Energy Commission's forecast.

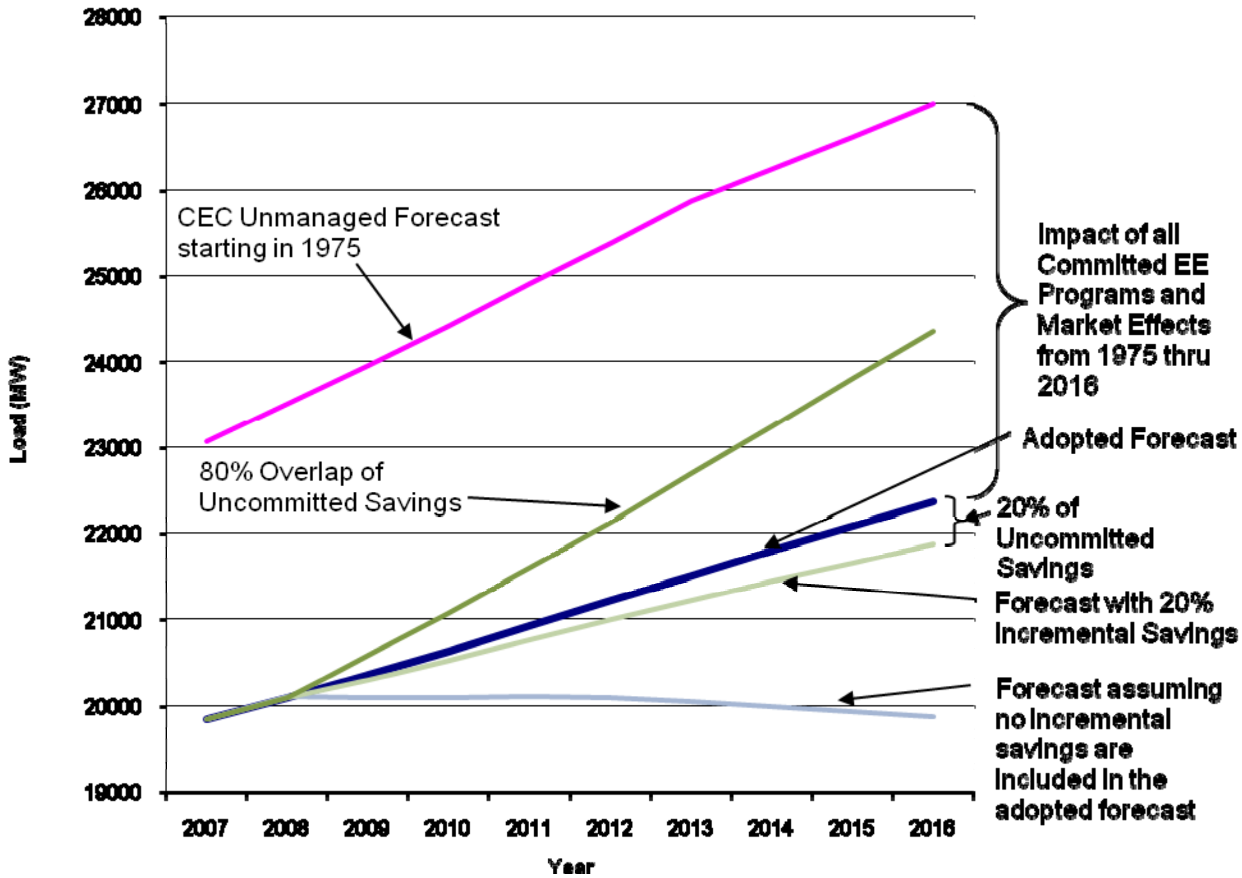
The utilities' claim created a debate about what portion of uncommitted savings impacts could be considered incorporated in the forecast, and what portion were incremental to the Energy Commission's demand forecast. As a temporary solution, the CPUC recommended an overlap factor of 80 percent of uncommitted savings be used for PG&E and SCE (20 percent considered incremental) and 100 percent for SDG&E.[76] The consequence of this decision is that only relatively small portions of uncommitted energy efficiency impacts are to be considered as a resource addition meant to diminish the need for supply-side resources.

Figure 1 shows the implications of this decision, using PG&E as an example. The top most curve shows the Energy Commission demand forecast for PG&E on an unmanaged basis, that is, a forecast that does not include any impacts from committed energy efficiency programs or market effects from 1975 onward. The distance between this curve and the one showing the

75 Adjustments to gross savings to account for free ridership and spillover effects from other programs.

76 D.07-12-052, CPUC, December 2007. The higher percentage applied to SDG&E reflects higher efficiency goals in percentage terms, so that a 20 percent incremental impact could lead to an unrealistically low projection of energy use for procurement.

Figure 1
Illustration of CPUC Adjustments for Incremental Efficiency Savings
(PG&E Service Area Values)



Source: California Energy Commission

adopted forecast represents the amount of committed savings and market effects incorporated in the forecast. Two additional lines show the implied impacts of an overlap factor for uncommitted savings of 80 percent; the distance between the curve labeled "80% Overlap of Uncommitted Savings" and the adopted forecast curve represents the amount of uncommitted savings impacts that would already be embedded in the forecast under the 80 percent assumption. The corresponding line labeled "Forecast with "20% Incremental Savings" shows the actual impact on the forecast from uncommitted savings under this assumption. As the figure shows, the magnitude of embedded uncommitted savings versus all committed savings and market effects would increase to an implausible level. In fact, embedded uncommitted programs would eventually become the largest single source of savings in the adopted forecast. On the other hand, assuming that no uncommitted savings are embedded in the forecast, meaning all uncommitted savings would be subtracted, yields a declining forecast (bottom line) that some would consider unrealistic.

This figure and discussion are meant to illustrate the complexity of the uncommitted savings issue. The percentages settled on are mere guesses, and the CPUC directed the IOUs to participate in the *2009 IEPR* process to improve upon this interim solution. Consequently, to address this issue, the IEPR Committee has directed staff to refine efficiency measurement and attribution within the Commission's demand forecast, as discussed in the next section.

Refining and Improving Efficiency Measurement and Attribution in the Demand Forecast

On March 11, 2008, the Energy Commission's IEPR Committee conducted a workshop on efficiency attribution and measurement and issues related to the incremental effect of near-term efficiency programs and long-term efficiency potential beyond the adopted demand forecast. As a result, the IEPR Committee agreed to better delineate the impacts of energy efficiency within the Energy Commission's demand forecast and to increase the ability to project the effects of energy efficiency programs.

On August 12, 2008, the IEPR Committee held a workshop to address these issues. Participants discussed a set of efficiency terms, concepts, and definitions, and staff presented a proposed approach to improve and refine efficiency attribution and measurement. The approach included plans to develop a working group dedicated to exploring technical issues related to efficiency measurement. In addition, a panel of utility representatives and Energy Commission staff discussed modeling issues related to efficiency at the workshop. Utility representatives were asked to provide details on their approaches to incorporating efficiency programs in their forecasts. Stakeholders at the workshop provided feedback on staff's approach and provided subsequent written comments. More details on the feedback and comments are given below.

To address the IEPR Committee's recommendations, as well as concerns voiced by stakeholders, Energy Commission staff has begun a process to make efficiency attribution and measurement more transparent to users of the demand forecast; refine and improve modeling methods; and develop efficiency measurement capabilities not currently part of the forecasting process.

The Energy Commission staff is to complete the following steps within the *2009 IEPR* cycle:

- Develop a standardized classification of terms encompassing all major concepts applying to efficiency potential studies and energy demand forecasts. (September – November 2008)
- Organize and participate in a stakeholder working group designed to address technical efficiency issues and to develop consistent measurement standards for efficiency analysis across utilities and various agencies. (Organized September 2008)
- Review and compare the modeling methods, inputs, and data sources used in Commission forecasts of efficiency savings with the Itron Asset Model. Compare interim savings estimates from the Energy Commission's demand forecast and Asset Model for selected programs given common sets of input and modeling assumptions. (September – November 2008)

- Refine and improve the Energy Commission's forecasting models to allow more detailed and complete output of committed efficiency savings. (December – June, 2009)
- Investigate alternative forecasting methods (Ongoing)
- Develop an uncommitted energy efficiency projection capability. (June – July, 2009)

In addition, staff plans to develop an in-house method after 2009 for the analysis of high-efficiency scenarios. This method would support the analysis of efficiency goals within proceedings, such as those of Assembly Bill 32.

A more detailed discussion of each step is presented below.

Develop Standardized Terms

Understanding the level of current and future efficiency program savings embedded in any forecast of future electricity demand requires precise definitions of efficiency-related concepts and methods.[77] However, little time has been spent standardizing these concepts and methods across the Energy Commission's demand forecast and other forecasting methods. To resolve any differences among various organizations and to investigate the need for additional terminology, staff and Itron proposed a preliminary list of common terms and associated definitions to be used in Energy Commission forecasting, IOU-CPUC program impact reporting, and IOU-CPUC efficiency potential analyses at the August 12, 2008, IEPR workshop. Workshop participants supported the list's usefulness and necessity. Based on comments received from parties, additional terminology will be incorporated, certain definitions clarified, and contextual examples added. Refinement and resolution of differences will continue through an efficiency working group being organized by the Energy Commission (see below).

Organize and Participate in an Efficiency Working Group

To address technical efficiency issues and establish common metrics for measuring savings impacts across the various forecasting methodologies, the Energy Commission is organizing a working group of utility forecasters and efficiency experts as well as Energy Commission and CPUC's Energy Division and Division of Ratepayer Advocates staff. Other organizations, such as the Natural Resources Defense Council and ARB, may also be asked to participate. Staff has proposed the following set of tasks to be undertaken or reviewed by this working group:

- Develop a common set of efficiency concept and method definitions, as discussed above.
- Develop an efficiency measure saturation database showing saturation growth through time.
- Develop an improved characterization of utility programs for lighting measures to determine how existing programs will help to achieve Assembly Bill 1109 (Huffman and Feuer, Chapter 534, Statutes of 2007) lighting reduction goals.
- Develop and/or acquire a database showing marginal efficiency distribution through time for each major end-use.

---

77 For example, conservation versus efficiency and committed savings versus uncommitted savings.

- Develop electricity rate projections incorporating new ranges of expected fuel prices, generation addition cost implications, and AB 32 greenhouse gas mitigation strategy implications.
- Conduct a modeling comparison among various forecasts (Energy Commission, utility methodologies, and the Asset Model) investigating how each approach makes use of recorded consumption and peak data, efficiency measure impacts, saturation estimates, geographic location of customers, and weather phenomena, and how well outputs from each approach match the entire set of actual output data available.

Some of these group tasks are meant to support other steps discussed here. The working group will begin to meet in the fall of 2008. The Energy Commission expects the group to collaborate beyond the *2009 IEPR* cycle as new issues related to efficiency become apparent.

Review and Compare Efficiency Modeling Methods, Inputs, and Data Sources

The energy consulting firm Itron has developed the Asset Model to measure the effects of efficiency programs under various scenarios, and this model was used to support the CPUC's goal setting process. The Energy Commission, with consulting assistance from Itron[78], is comparing the modeling methods and input data used in the Commission's demand forecast with those used in the Asset Model. Staff is initially focusing on the inputs and methods used to estimate the savings from utilities' 2006-2008 commercial and residential lighting programs, followed by new construction and heating, ventilation, and air-conditioning programs. The analysis will also compare the techniques used to estimate incremental energy savings from new state or federal standards, and identify how each model estimates price and other market effects. The Energy Commission staff will highlight the major differences between the two approaches and, together with Itron, will attempt to resolve these.

The analysis will then focus on defining a common set of inputs for selected end uses within each method and comparing the savings estimates produced by each. Additionally, the analysis will compare estimates of program-induced savings relative to naturally occurring and price-induced savings. This will help reveal the extent of differences between independent estimates of program savings and those occurring within a model that simultaneously estimates savings from efficiency programs, price, and technological changes. Stakeholders supported this method to evaluate how well the forecast matches historical data. The Energy Commission staff will then propose adjustments to the demand forecasts or the reported program savings estimates so comparisons of savings between the two are consistent in the future.

Refine and Improve the Energy Commission's Forecasting Models

The Energy Commission staff will expand the capability to incorporate specific efficiency programs to other sectors, in addition to the residential and commercial. Staff is also working to improve the data inputs used to estimate baseline and program-induced energy intensities over

78 Energy Commission staff wishes to acknowledge and thank the CPUC for funding the assistance that Itron will provide.

time.[79] To this end, staff will further disaggregate end uses in the Energy Commission forecasting models to allow more detailed attribution of efficiency savings. For example, residential lighting, currently part of a miscellaneous category within the Residential Model, will be broken out into a separate category.

Staff will also review the analysis methods used in the energy demand forecast to ensure that simulated load forecasts that omit efficiency impacts truly capture the trends that would exist without these impacts.[80] Staff will test completed refinements in a preliminary energy forecast early in 2009 that includes estimated impacts of committed savings programs. Any refinements not yet incorporated will be part of a revised forecast in the summer of 2009.

Investigate Alternative Forecasting Methodologies

An independent evaluation of the Energy Commission forecasting methodology is underway, referred to as the Demand Forecast Assessment Project.[81] This assessment will make recommendations for improvements in the Energy Commission's demand forecasting methods and is evaluating alternative methods for forecasting energy consumption and efficiency impacts, including econometric approaches. It is possible the results, due in the fall of 2008, may affect the efficiency measurement and refinement steps discussed here.

In their comments for the August 12 workshop, utilities supported the consideration of alternative forecasting methods. PG&E urged the Energy Commission to develop an econometric model to be used "either as a stand-alone forecasting model or be used in conjunction with the existing end-use modeling approach." [82] While SCE believed recommending any one approach was premature, it encouraged the Energy Commission to "seriously consider new, more contemporary models"[83] for forecasting energy efficiency impacts.

Develop Ability to Project Uncommitted Energy Efficiency

Historically, the Energy Commission has satisfied the legal requirement that its forecast include "conservation reasonably expected to occur by incorporating only committed energy efficiency impacts in the baseline demand forecast and carrying uncommitted energy efficiency programs as supply-side resources. However, given the establishment of CPUC-required efficiency goals, which involve uncommitted programs, some of the utilities at the August 12 workshop questioned the need to distinguish between the two types of impacts with energy efficiency's cornerstone role under AB 32 in reducing greenhouse gases. The utilities contend business as usual policies clearly expect high levels of energy efficiency program funding throughout the forecast horizon to meet goals adopted out to 2020 for both energy and capacity reductions.

---

79 Energy intensity is the ratio between energy consumption and Gross Domestic Product.

80 This helps ensure that total efficiency impacts are properly measured.

81 Aspen Inc. and R.W. Beck are conducting the demand forecast assessment.

82 First Draft Written Comments of Pacific Gas and Electric Company Regarding Improvements to the Energy Commission Demand Forecast Following the IEPR Workshop of August 12, 2008, August 19, 2008, (p.2).

83 Written Comments of Southern California Edison Company for the August 12, 2008, IEPR Workshop, p.3.

The Energy Commission staff believe it is important to keep the distinction because uncommitted savings have no funding source or have not been passed into law, so there is less of a guarantee that these programs will actually come into existence and what impact they would have. However, staff intends to develop a new capability to assess uncommitted energy efficiency impacts separately, and is considering two choices:

1. Inserting additional program characteristics into the Energy Commission demand forecasting models and making another run of the models. The difference between the baseline run with "committed" characteristics and the second run would develop "uncommitted" impacts.
2. Adapt the Itron Asset model to make two sets of runs, with the difference being the impacts of a set of programs considered to be "uncommitted."

The approach will be determined after a full comparison of the Energy Commission and Itron Asset models, as described above.

Utility Progress Under Assembly Bill 2021

Assembly Bill 2021 (Levine, Chapter 734, Statutes of 2006) requires the Energy Commission and the CPUC to develop a statewide estimate of all potentially achievable cost-effective electricity and natural gas efficiency savings and establish targets for statewide annual energy efficiency savings and demand reduction for a 10-year period for both publicly-owned utilities and IOUs. Analysis and data of all cost-effective efficiency potential were prepared by Itron for the IOUs and by the Rocky Mountain Institute for the publicly-owned utilities.

The Energy Commission and the CPUC have adopted statewide savings goals consistent with these studies' measurement of all cost-effective efficiency potential.[84] The combined economic potential to save energy in 2016 for the IOUs and publicly owned utilities is estimated to be 39,500 gigawatt hours of electricity, 6,600 megawatts of peak electrical demand and 750 million therms of natural gas.

It should be noted that progress reported by utilities for the 2006-2008 period were *ex-ante* (estimated) impacts based on savings defined in the above mentioned studies and should not be assumed to equate to actual reductions in energy consumption or peak demand. Utilities are in the process of *ex-post* evaluation, measurement, and verification (EM&V) studies to determine the actual impact these programs have had on consumption and customer bills. The results of these studies may impact future assessments of progress in attaining the savings goals.

Investor-Owned Utility Energy Efficiency Progress

Table 3 provides the goals and *ex-ante* savings estimates reported by the combined IOUs for the 2006 and 2007 program years and the first six months of 2008. It should be noted that the goals shown in the table are those defined by the CPUC, which represent about 74 percent of cost-

84 California Energy Commission, *Achieving All Cost-Effective Energy Efficiency for California*, Final Staff Report, CEC-200-2007-019-SF, December 2007, http://www.energy.ca.gov/2007publications/CEC-200-2007-019/CEC-200-2007-019-SF.PDF.

effective potential for electricity savings, 98 percent of peak savings potential, and 73 percent of natural gas savings potential for the IOUs.

After a ramp-up period in 2006, as new programs were getting underway for the CPUC's 2006-2008 efficiency cycle, the combined IOU efficiency portfolios report savings that exceed the CPUC-defined goals in 2007 and are on track to do so again for the 2008 goals.[85]

Table 3 – IOU Reported Efficiency Savings and CPUC Annual Efficiency Goals for Electricity and Natural Gas

	2006			2007			2008		
	GWh	MW	MMTh	GWh	MW	MMTh	GWh	MW	MMTh
CPUC Goal	2,032	442	30	2,275	478	37	2,505	528	44
IOU Reported Savings	1,718	300	24	3,872	638	52	2,059	359	27
Percentage of Goal	85	68	80	170	133	141	82	68	61

Source: the CPUC website (http://eega2006.cpuc.ca.gov) and CPUC Energy Division staff.

Publicly Owned Utility Energy Efficiency Progress

Estimated efficiency savings reported by publicly owned utilities increased substantially from 2006 to 2007. [86] The aggregate electricity consumption savings reported by publicly owned utilities reached 75 percent of AB 2021 adopted goals in 2007, while electricity peak savings reached 62 percent.[87] These results are noteworthy given that the publicly owned utilities' 2007 savings projections were developed prior to the actual adoption of the AB 2021 goals in December 2007.

Publicly owned utilities have demonstrated their commitment to increased efficiency savings over the last year by expanding both efficiency staffing and customer programs. Energy Commission staff is concerned, however, about the ability of the publicly owned utilities to meet adopted goals for 2008. To meet these goals, publicly owned utilities will require a substantial savings improvement from 2007. Savings for the 15 largest publicly owned utilities combined, for example, would have to increase by 130 percent over a one-year period. This seems a formidable task, particularly given the already substantial increase realized from 2006 to 2007.

85 The savings estimates come from the CPUC website (http://eega2006.cpuc.ca.gov) and from CPUC Energy Division staff.

86 Savings estimates come from California Municipal Utilities Association, *Energy Efficiency in California's Public Power Sector: A Status Report*, March 2008.

87 There were no reported natural gas savings for publicly owned utilities in 2007. The City of Palo Alto's natural gas savings program is newly initiated and will not yield savings until 2008.

In 2007, when publicly owned utilities submitted efficiency goals to the Energy Commission, staff expressed concern over unprecedented increases or “ramp-up rates”, proposed between 2007 and 2011 that would be difficult to achieve. Efficiency planners likely had ramping in mind when they projected their efficiency goals for 2008. Of the large publicly owned utilities that fell short of their adopted goals in 2007, half project achieving or nearing their 2008 adopted goals. The remaining large publicly owned utilities made revised energy and peak savings projections for 2008 that are less than the goals adopted in 2007. While this may be more realistic when developing savings projections, it is in direct contradiction to the AB 2021 goals and a departure from *2007 IEPR* direction to achieve all cost-effective efficiency savings.

Publicly owned utilities need to continue to be proactive in meeting the adopted goals. It is clear from the cost-effectiveness data provided for each utility’s portfolio that publicly owned utilities could expand their programs and benefit their customers and society as a whole. Such an expansion should be considered in light of the Legislature’s mandate specifically requiring publicly owned utilities to give first consideration to energy efficiency when planning for energy resources to meet customer loads.

The publicly owned utilities have stated that their procurement investments are reserved for operational improvements (generation, transmission, and distribution upgrades), while efficiency expenditures are handled through public goods charge allocations. However, public goods charge allocations for the publicly owned utilities are insufficient to achieve the savings needed to meet all cost-effective energy efficiency. In addition, this practice contradicts the Energy Commission’s stated policy to use procurement funds for expanding efficiency programs and requires exploration that should begin with more detailed reporting of sources for publicly owned utility investments in energy efficiency.

Conclusions

The publicly owned utilities are in the first year of AB 2021 mandated goals that have a 10-year time horizon (2007-2016). Energy Commission staff sees evidence that the publicly owned utility community is on the right long-term track. Goals will be reset in 2010 for 2011–2020. The ultimate resource value of these efficiency program savings will be determined through EM&V studies. Eleven publicly owned utilities are developing, or have contracted to develop, program evaluation plans to determine savings impacts, according to the March 2008 report. The publicly owned utilities have much to gain from EM&V; most importantly, these results will make their savings estimates more credible and reliable in statewide energy and climate change planning forums.

The recent focus on energy efficiency in California has heightened the need for proper accounting of efficiency and other savings impacts. This chapter has discussed the challenges involved in this accounting, including the uncertainties and lack of consistency among various organizations that must be addressed. Energy Commission staff has, as described in this chapter, undertaken a major effort to update and improve methods for the measurement and attribution of efficiency impacts within the Energy Commission’s demand forecast, assisted by the CPUC through the work of Itron. Utilities have also offered their support and expressed their willingness to take part in a technical working group. Commission staff plans on making substantial progress over the *2009 IEPR* cycle, although it is likely that at least some refinements will still be unfolding through the IEPR cycle in 2011.

Staff plans to release a preliminary energy forecast in February 2009, which will incorporate revisions to the forecasting methodology. A subsequent workshop will allow staff to present these revisions to stakeholders, who would be encouraged to provide comments and suggestions. A revised forecast, planned for May 2009, will incorporate feedback from public comment and other revisions discussed in the proposed staff plan not yet integrated into the forecasting models.

Recommendations

- The Energy Commission should conduct an analysis of the relationship between end use impacts as modeled in the Energy Commission's demand forecast compared to how these impacts are characterized in efficiency program planning should be a high priority activity for the *2009 IEPR*. Ignoring this potential overlap will only give rise to misleading estimates of how much can be achieved through future efficiency strategies.
- The IEPR Committee encourages IOUs and publicly owned utilities, regulatory agencies, and other interested stakeholders to participate in the proposed working group to pursue the Demand Forecast-Energy Efficiency Quantification Project. The working group should focus both on technical issues and effectively communicating results to all interested stakeholders.
- The IEPR Committee recommends that independent efforts to investigate and evaluate alternate forecasting methods be continued in the *2009 IEPR*. These efforts should focus on matching appropriate methods to the various purposes to which the demand forecast is applied.
- The Energy Commission should continue to work with publicly owned utilities to understand the processes used by individual utilities to estimate their remaining economic potential and set targets
- The Energy Commission staff should continue to assist the publicly owned utilities in achieving their efficiency goals through workshops and collaborative efforts that improve overall evaluation planning, develop program tracking systems, and improve savings reporting requirements for the next AB 2021 cycle.

CHAPTER 3: Electricity Procurement Practices and Resource Planning Activities

Introduction

This chapter summarizes the recommendations in the *2007 Integrated Energy Policy Report (2007 IEPR)* regarding resource planning and procurement and reports on progress to date in implementing those recommendations. It also provides recommendations for further activities, including analysis to be done for the *2009 IEPR*.

The *2007 IEPR* recommended that the Energy Commission and the California Public Utilities Commission (CPUC) work together to improve the analysis methods used by the state's investor-owned utilities (IOUs) in their long-term procurement plans. The *2007 IEPR* stated that the IOUs' analyses should use common assumptions as much as possible; adequately reflect significant ratepayer risks; extend over a 20- to 30-year period of analysis; incorporate environmental impacts and risks; and discount future fuel costs at a social discount rate to properly reflect the risk associated with their volatility.

The IEPR Committee held two workshops on procurement issues on July 14 and August 18, 2008. The July 14 workshop focused on the use of procurement review groups in utility procurement. Members of these groups, subject to a non-disclosure agreement, consult with utilities and review procurement strategies, solicitations, and proposed contracts. The *2005 IEPR* recommended eliminating the use of procurement review groups in favor of a more open and transparent resource planning and procurement process, and the Energy Commission subsequently withdrew from participation in the procurement review groups.

The August 18 workshop focused on long-term procurement planning, including the status of collaborative efforts between the Energy Commission and the CPUC in the CPUC's 2008 long-term procurement proceeding, progress made toward implementing the procurement recommendations in the *2007 IEPR*, and how to incorporate environmental impacts into long-term procurement. At that workshop, the Committee noted that while the CPUC is the agency with primary responsibility for electricity procurement activities, the Energy Commission shares the CPUC's interests and concerns that California's electricity supply is both reliable and least cost, as well as meeting other goals such as increasing the procurement of renewable energy.

Other issues related to procurement covered in this chapter include a discussion of reliability and resource adequacy issues associated with transitioning away from the use of once-through cooling in power plants and the relationship of electricity procurement to the Energy Commission's power plant siting process.

Long-Term Procurement Plans

During the past five years, the CPUC has developed processes for resource planning and procurement to be used by the state's major IOUs. This has been a gradual process, and not without difficulty given current dynamic market conditions, nascent market structure, and evolving legal and policy environments.

Since 2004, the CPUC has required the major IOUs to submit biennial 10-year plans for acquiring energy resources to meet demand growth and state targets for preferred resources – energy efficiency, demand response, and renewable energy – and for replacing expiring contracts. These long-term procurement plans (LTPPs) must balance the costs of meeting customer needs with state policy goals of minimizing environmental impacts and meeting state targets for preferred resources.

In preparing the plans, IOUs do two assessments, one to identify physical and contractual resources needed to meet bundled customer needs and one to identify new resources needed in their service territories to maintain adequate reserve margins. The latter assessment takes into account potential power plant retirements; for instance, the current assumption for PG&E is that aging plants in Northern California will be retired by 2015, while SCE assumes aging plants in Southern California will be retired by 2018.

After approving the LTPPs, the CPUC authorizes the IOUs to procure the resources needed to meet long-run growth in energy demand and cover the expiration of existing contracts. The CPUC sets targets over the next 10 years for energy efficiency, demand response and interruptible load programs, and renewable energy. The utilities provide estimates of the remaining need for energy and capacity in their LTPPs and then solicit long-term agreements through competitive requests for offers (RFOs) overseen by the CPUC.

In December 2006, the IOUs submitted plans for 2007 through 2016, which were approved by the CPUC in December 2007. Parties to the 2006 proceeding criticized the plans on several grounds, most notably that the assessment methods did not allow plans to be compared across utilities or adequately evaluate high natural gas prices and greenhouse (GHG) regulation, which are the most significant risks to ratepayers. The Energy Commission reflected these concerns in the *2007 IEPR* recommendations.

The CPUC acknowledged these shortcomings in its decision approving the 2006 plans.[88] That decision influenced the structure of the 2008 LTPP proceeding, which opened in February 2008 and in which the Energy Commission is collaborating. The 2008 LTPP proceeding is focusing primarily on the following two topics:

- Standardized resource planning practices, assumptions, and analytic techniques applied in long-term procurement plans.

88 D.07-12-052; December 20, 2007

- Interim standards and practices to evaluate the uncertain cost of future GHG regulations during AB 32 implementation and in anticipation of possible federal legislation.

The CPUC intends to resolve issues relating to these topics before issuing directions to the IOUs on preparing their 2010 LTPPs in April 2009. The CPUC expects to receive the IOUs' 2010 plans, covering 2011 through 2020, in late 2009 followed by CPUC approval in 2010.

The following sections discuss progress toward meeting the *2007 IEPR* procurement recommendations in more detail, including standardizing assumptions and looking at the portfolio of resources, incorporating environmental impacts and uncertainties, using a 20-year or longer analysis period, and discounting future fuel costs.

Portfolio Methodology

In the 2008 LTPP proceeding, the CPUC is directing the IOUs to provide a set of plans in 2010 that can be compared and aggregated and that also adequately considers ratepayer risks. The following principles reflect the CPUC's desire to evaluate utility portfolios using a standardized, transparent method that reflects uncertainties like future natural gas prices and carbon costs:

- The plans should use standardized inputs (where appropriate), formats for reporting outputs, and measures of performance, so that plans are based on consistent and well-reasoned assumptions regarding demand growth and fuel and resource development costs, and can be easily compared and aggregated.
- The plans should evaluate potential portfolios under a wide range of values for key variables that strongly influence costs (for example, natural gas prices or GHG costs) to determine the sensitivity of individual and aggregate portfolio costs to those key variables.
- The plans should use identical "scenarios," where portfolios are developed and evaluated using an internally consistent set of input assumptions that define specific futures (such as a "high natural gas cost world," or a "low carbon price world"). This allows parties to accurately evaluate and compare the cost and performance of utility portfolios under different sets of market conditions over the next 10 years.
- The plans should report on performance measures that incorporate risks, such as different cost ranges in the value of key variables and estimates of portfolio costs in different scenarios, to allow parties to evaluate both expected and potential costs.

The *2007 IEPR* discussed the Northwest Power and Conservation Council's (NWPCC) analytical software, which allows comparison of many more portfolios than will be possible in the 2010 proceeding. The software, however, cannot be applied to procurement decisions of an individual utility faced with numerous transmission and operating constraints. Enhanced development of the NWPCC's software, combined with review of the 2010 plans and clarification of future GHG regulations, will help determine the need for new software tools for evaluating resource planning decisions.

Incorporating Environmental Impacts and Uncertainties

In the 2006 LTPP proceeding, parties were concerned that the plans did not sufficiently analyze the potential effect of GHG regulations on utility portfolios and portfolio cost. In the 2008 LTPP proceeding, the CPUC asked parties how to best evaluate GHG regulations given uncertainties about possible regulatory regimes (like cap-and-trade), the relative costs of reducing GHG emissions across economic sectors, and the allocation of emission allowances across utilities.[89] Most parties replied that using a range of carbon costs to represent the potential impact of GHG regulation would be an adequate interim measure in the 2010 proceeding, but that the range must be wide enough to adequately reflect the risks faced by ratepayers.

Developing such a range of values will be somewhat subjective because there is little, if any, empirical data that can provide a sound basis for development of a range based on probability analysis. As more information becomes available regarding regulatory regimes and allocation of emission allowances, the LTPP analysis is expected to incorporate more explicit modeling of GHG regulation and any necessary software modifications.

Using 20-Year or Longer Analysis Period

Currently, the IOUs submit plans in the LTPP proceeding covering a 10-year planning horizon. The *2007 IEPR* recommended that this be extended to 20 or 30 years.

Stakeholder comments in the 2008 LTPP proceeding reflected a desire to have plans cover a period of 20 years or more. Utility responses were mixed, with Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric (SDG&E) contending that uncertainties associated with market conditions, regulation, and technology severely limit the value of analysis beyond 10 years. Southern California Edison, however, recommended extending the analysis period to 20 years, noting that investment decisions made in the near term could affect the mix of generating assets that is feasible in later years. The Center for Energy Efficiency and Renewable Technology (CEERT) called for an assessment of the GHG reductions possible from extrapolating energy efficiency and renewable energy procurement during 2010 – 2020 out to 2030. The Natural Resources Defense Council (NRDC) and Union of Concerned Scientists stated that sufficient data exists to develop least-cost utility portfolios through 2030, but that actions taken to meet 2020 GHG reduction targets may not be compatible with actions necessary to meet higher targets for 2050. For example, NRDC recommends that utilities might focus on the cheapest opportunities to reduce GHG emissions by 2020, which could improve subsequent LTPPs and increase the long-term costs and difficulties of attaining the 2050 goal. Also, while continued growing demand for low- or no-carbon resources may result in technological development and cost reductions, these could be discounted or underestimated if a shorter analysis period is used.

89 Administrative Law Judge's Ruling Scheduling July 10, 2008, Workshop On Greenhouse Gas (GHG) Uncertainty And Requesting Comments, June 6, 2008.

As analyses focus on longer planning horizons, there is greater uncertainty regarding the likely and potential values of the following key variables that drive the cost and potential content of utility portfolios:

- Electrification of the transportation sector and other sectors of the economy in response to GHG regulation may increase electricity demand in the post-2020 period and possibly alter its daily profile, increasing the need for energy in what are currently low load hours.
- Natural gas prices, and thus the cost of gas-fired generation, may climb dramatically because of increasing global demand. On the other hand, the development of shale reserves and increased reliance on renewable and clean coal technologies may moderate price increases beyond 2020.
- The absolute and relative costs of preferred resources (energy efficiency and renewable generation) will change as technologies mature and new ones are developed.
- Long-run GHG reduction targets may require disproportionate contributions from the electricity sector. This depends on the targets set and the cost of extracting emission reductions from the electricity sector and other parts of the economy. Other long-run issues and associated uncertainties identified in the 2008 LTPP proceeding include the development of smart grid technologies and their impact on the availability of clean generation connected at the distribution level, and the impact of interstate competition on the availability and cost of out-of-state renewable resources.

Currently, the CPUC has not decided on a planning horizon for the 2010 plans. The time and resources needed to complete the 2008 proceeding may preclude consideration of longer-term analysis in the 2010 plans, but the CPUC may consider this for subsequent filings. If the 2010 plans do look at a longer period than 10 years, it is possible that the post-2020 assessments will use a different set of analytical tools and methods and consider a different or smaller set of issues.

Discounting Future Fuel Costs at a Social Discount Rate

Discount rates are used to determine the present value of a future sum. Higher discount rates essentially place a low value on the future, while low discount rates represent a higher value on the future.

The *2007 IEPR* identified current methods for discounting future natural gas fuel costs as issues of concern because the discount rate that is used makes these costs appear unrealistically inexpensive. The concern is that this would lead to increased dependence on natural gas-based generation because alternatives, such as renewables and efficiency, would be undervalued.[90] Accordingly, the *2007 IEPR* recommended applying a 3 percent social discount rate (lower than the current discount rate, which is based on the utility's cost of capital) to future natural gas costs to more accurately reflect the risks of cost volatility of natural gas-based generation.

90 California Energy Commission, *2007 Integrated Energy Policy Report,* CEC-100-2007-008-CMF, p. 64.

For the *2008 IEPR Update,* the IEPR Committee directed staff to identify the consequences of using a social discount rate.[91] Staff presented a paper, *Discounting Future Fuel Costs at a Social Discount Rate*, at the August 18, 2008, IEPR workshop and received comments on the use of social discount rates in economic analyses of electric generation projects.

There are two different views on how to use discount rates under conditions of uncertainty: Discount rates should not be affected by the uncertain nature of the future cash flows and should be based on the cost of capital, or discount rates should be adjusted for risk to reflect the uncertainty of the cash flows in question, so that based on the market values of those cash flows, high-risk costs should be discounted at lower rates. These views reflect a difference in perspective (finance theory vs. decision analysis) when evaluating potential investments. Finance theory takes the investor's perspective and often applies a risk-adjusted discount rate to a single expected cash flow to estimate the market value of an investment. Decision analysis assumes the perspective of the corporate decision maker and considers project-specific risks by evaluating each of a number of uncertain cash flow scenarios using a risk-free (unadjusted) discount rate.

Some observers argue that discount rates should not be risk-adjusted because of a variety of analytical and conceptual problems. Others argue that unintended consequences could result from using discount rates that are lower than either the utility or ratepayer cost of capital, such that using a social discount rate could displace projects with higher benefits.

Under the CPUC's current energy efficiency incentives framework, using a social discount rate could allow utilities to receive greater incentives for the same amount of efficiency, with ratepayers paying more per unit of energy conserved. In its review of federal government discount rate policy, the White House Office of Management and Budget concluded that "in general, variations in the discount rate are not the appropriate method of adjusting net present value for the special risks of particular projects." [92]

There is general agreement about the importance of incorporating uncertainty and risk (including fuel price uncertainty) into the overall planning and decision-making process. In the *2007 IEPR*, the Energy Commission recognized the suitability of the IOUs' long-term planning process for considering the comparative risk of different utility investments when it "recommended making the development of a common portfolio analytic methodology a core focus of the *2008 IEPR Update*, with the clear objective of influencing the long-term procurement plans filed by the investor-owned utilities with the CPUC…" [93]

Since the adoption of the *2007 IEPR*, the CPUC issued Decision 07-12-052, which stated:

---

91 The social discount rate measures the rate at which a society would be willing to trade present for future consumption.

92 White House Office of Management and Budget, *Guidelines and Discount Rates for Benefit-Cost Analysis of Federal Programs*, Circular No. A-94, October 29, 1992, section 9.d.

93 California Energy Commission, *2007 Integrated Energy Policy Report*, p. 48.

> The methodology established in the Scoping Memo for long-term renewable resource planning was not as robust as we believe is necessary for effective resource planning decisions; therefore, we direct the IOUs to…refine this planning methodology. We anticipate a methodology that employs an integrated portfolio approach.[94]

In February 2008, the CPUC convened the LTPP Rulemaking (R.08-02-007) to address analytical techniques applied in LTPPs based on an integrated resource planning framework. The Energy Commission anticipates that the CPUC will require the next round of LTPPs to be based on an integrated resource planning framework, incorporating risk-based portfolio analysis. The plans will incorporate a wide range of future natural gas prices and include the associated gas price risk. The Energy Commission staff will continue to collaborate with CPUC staff in R.08-02-007 to ensure that fuel price risk is properly considered in the long-term planning process.

The Energy Commission believes that the CPUC's Rulemaking could result in a planning process that properly incorporates long-term natural gas price risk in the construction of utility portfolios. The planning process is a more direct and transparent method to account for potential gas price risk than the adjustment of discount rates. The degree to which discount rates should be adjusted to reflect risk continues to be controversial and, under some conditions, could result in unintended consequences.

Aging Plants and Transitioning From Once-Through Cooling

The *2005* and *2007 IEPRs* called for the orderly retirement of more than 17,000 MW of aging gas-fired generation in the California fleet, and the State Water Resource Control Board (SWRCB) is proposing a statewide policy on Clean Water Act 316(b) regulations regarding the use of once-through cooling (OTC) by coastal power plants that has given new urgency to proactive fleet management. More than 21,000 MW of the state's generation fleet uses OTC, approximately 15,200 MW of which is aging capacity recommended for retirement in the *2005 IEPR*.[95] In March 2008, the SWRCB issued a draft proposal calling for the phased elimination of OTC between 2015 and 2021, with a final proposal expected in January 2009. Without alternative mitigation measures, accomplishing this will require the refitting, repowering, replacement, or retirement of 19 power plants, representing nearly 40 percent of the state's generation capacity.[96] A list of aging and OTC plants is shown in Table 4.

94 CPUC Decision 07-12-052, p. 76.

95 The major facilities using OTC that were not nominated for retirement in the *2005 IEPR* are the nuclear facilities at Diablo Canyon (2,200 MW, in-service 1985) and San Onofre (2,254 MW, 1983), Moss Landing 1-2 (1,080 MW, 2002), Haynes 9-10 (575 MW, 2005), Huntington Beach 3-4 (450 MW, 2002), and Moss Landing 1-4 (1,060 MW, 2002).

96 "Refitting" refers to modifying the cooling technology used so as to comply with the rule; "repowering" involves replacing the boiler, but retaining the steam turbine. "Replacement" entails replacing both components, effectively erecting a new power plant on the site. In its comments on the SWRCB's preliminary draft policy, the Energy Commission asked that the licensing conditions for recently sited facilities be considered an alternative form of compliance. See California Energy Commission, *California Energy Commission Comment to State Water Resources Control Board Concerning its Coastal Power Plant Cooling Preliminary Draft Policy and Related Scoping Document*, May 20, 2008.

Table 4. Aging and Once Through Cooling Power Plants

September 2008

Plant	Unit	Year First in Service	OTC	Plant Original Capacity	2007 Capacity Factor	County	LCR AREA NAME	Owner	Upgrades, Repower or Replacement Completed, Planned or In Process
Alamitos	1	1956	YES	175	2	Los Angeles	LA Basin	AES Southland/ Bear Energy	
Alamitos	2	1957	YES	175	2	Los Angeles	LA Basin	AES Southland/ Bear Energy	
Alamitos	3	1961	YES	320	19	Los Angeles	LA Basin	AES Southland/ Bear Energy	
Alamitos	4	1962	YES	320	10	Los Angeles	LA Basin	AES Southland/ Bear Energy	
Alamitos	5	1969	YES	480	9	Los Angeles	LA Basin	AES Southland/ Bear Energy	
Alamitos	6	1966	YES	480	7	Los Angeles	LA Basin	AES Southland/ Bear Energy	
Broadway	3	1965	NO	66	2	San Diego		City of Pasadena	none-slow start only used for long hot spell
Carlsbad (Encina)	1	1954	YES	107	6	San Diego	San Diego	NRG	CEC AFC in process for a new 300 MW peaking power plant, air-cooled , low profile, where two old fuel tanks now sit at the Encina site. Units 1-3 to be shut down. Would use some ocean water
Carlsbad (Encina)	2	1956	YES	104	5	San Diego	San Diego	NRG	
Carlsbad (Encina)	3	1958	YES	110	8	San Diego	San Diego	NRG	
Carlsbad (Encina)	4	1973	YES	293	8	San Diego	San Diego	NRG	
Carlsbad (Encina)	5	1978	YES	315	12	San Diego	San Diego	NRG	
Contra Costa	1,2,3	1951	YES	348	NA	Contra Costa	Bay Area	PG&E	CEC permit for Gateway plant (Contra Costa 8) repower of Units 1, 2, and 3 (retired by 1994) would have used OTC facilities of Units 6-7. Permit amended August 2007 to use dry cooling.
Contra Costa	4	1953	prev	117	NA	Contra Costa	Bay Area	Mirant	retired 1996, used as Syn Condenser
Contra Costa	5	1953	prev	115	NA	Contra Costa	Bay Area	Mirant	retired 1996, used as Syn Condenser
Contra Costa	6	1964	YES	340	1	Contra Costa	Bay Area	Mirant	

Table 4. Aging and Once Through Cooling Power Plants

September 2008

Contra Costa	7	1964	YES	340	3	Contra Costa	Bay Area	Mirant	none-Mirant has awarded a contract valued at $1.4 million for a turnkey process control upgrade at its Contra Costa Unit 7
Coolwater	1	1961	NO	65	1	San Bernardino		Reliant	
Coolwater	2	1964	NO	81	1	San Bernardino		Reliant	
Coolwater	3	1978	NO	241	16	San Bernardino		Reliant	
Coolwater	4	1978	NO	241	21	San Bernardino		Reliant	
Diablo Canyon	1	1985	YES	1090	92	San Luis Obispo		PG&E	Steam Generator Replacement scheduled for 2009
Diablo Canyon	2	1986	YES	1105	101	San Luis Obispo		PG&E	Steam Generator Replacement completed 2008
El Segundo	1	1955	prev	175	NA	Los Angeles		NRG	2007 petition to amend CEC permit in process-will eliminate OTC. 560 MW repower; demo of old units approved 8-2007. new combined cycle units will be called 5, 6, and 7
El Segundo	2	1956	prev	175	NA	Los Angeles		NRG	
El Segundo	3	1964	YES	335	9	Los Angeles	LA Basin	NRG	
El Segundo	4	1965	YES	335	9	Los Angeles	LA Basin	NRG	
El Centro	3	1952	YES	44	11	Imperial		IID	CEC permit to repower issued January 2007; capacity increased to 128 MW; efficiency increase about 30% and reduce water consumption by about 60% for every MWH generated.
El Centro	4	1968	YES	74	20	Imperial	LA Basin	IID	Plan to repower to 240 MW in the future
Etiwanda	1	1953	NO	132	NA	San Bernardino	LA Basin	Reliant	Retired 2004, last operated 2002
Etiwanda	2	1953	NO	132	NA	San Bernardino	LA Basin	Reliant	
Etiwanda	3	1963	NO	320	14	San Bernardino	LA Basin	Reliant	Multiyear tolling agreement with RA capacity contract signed with SCE. Peaker plant (45MW) installed in summer of 2007.
Etiwanda	4	1963	NO	320	9	San Bernardino	LA Basin	Reliant	
Etiwanda	5	1969	NO	NA	NA	San Bernardino	LA Basin	Reliant	Retired 2003

Table 4. Aging and Once Through Cooling Power Plants
September 2008

Grayson	3	1953	NO	19	NA	Los Angeles		Glendale	Represents approximately 55% of the City's generation capacity, but used for intermediate and peaking; provides only 15% of the City's energy needs. Unit 3 retired January 2008. Units 6 & 7 declared obsolete 2005, replaced by Unit 9; Sept 2008 RFO for overhaul of Unit 8. Newer Magnolia plant is base load.
Grayson	4	1959	NO	44	5	Los Angeles		Glendale	
Grayson	5	1964	NO	42	30	Los Angeles		Glendale	
Grayson	8A & 1 or 2	1977	NO	32	NA	Los Angeles		Glendale	
Grayson	8B/C &1or 2	1977	NO	74	NA	Los Angeles		Glendale	
Harbor	1	1994	YES	227	9	Los Angeles		LADWP	No major repowering plans. Investigating possible use of reclaimed water
Haynes	1	1962	YES	200	29	Los Angeles		LADWP	Units 3 and 4 were repowered in 2005 using OTC. Units 5 and 6 will be replaced with six hybrid simple cycle turbines by late 2011. Then, Units 1 and 2 will be replaced with new technology.
Haynes	2	1963	YES	200	22	Los Angeles		LADWP	
Haynes	5	1967	YES	318	4	Los Angeles		LADWP	
Haynes	6	1967	YES	318	17	Los Angeles		LADWP	
Haynes	CC	2005	YES	575	50	Los Angeles		LADWP	
Humboldt Bay	1	1956	prev	52	90	Humboldt	Humboldt	PG&E	CEC permit for repower with Wartsila, 163 MW, 2009, 35% more eff, diesel back up. Replaces these four units and Unit 3 capacity. Permits for old units will be surrendered
Humboldt Bay	2	1958	prev	53	28	Humboldt	Humboldt	PG&E	
Hunters Point	4	1958	prev	163	NA	San Francisco	Bay Area	PG&E	Units 2 and 3 converted to synchronous condensers in 2001, plant closed 2006. Plant demolished 2008.
Huntington Beach	2	1958	YES	215	6	Orange	LA Basin	AES Southland/ Bear Energy	
Huntington Beach	3	1961	YES	215	25	Orange	LA Basin	AES Southland/ Bear Energy	2002 retool-license extended 5 years
Huntington Beach	4	1961	YES	225	12	Orange	LA Basin	AES Southland/ Bear Energy	2003 retool-license extended 5 years
Long Beach	8	1976	prev	303	NA	Los Angeles		NRG	CEC permit issued for 260 MW, 2007, replaced old capacity with CTs 1-4 peakers BACT August 2007. No longer OTC
Long Beach	9	1977	prev	227	NA	Los Angeles		NRG	

Table 4. Aging and Once Through Cooling Power Plants

September 2008

Mandalay	1	1959	YES	215	9	Ventura	Big Creek/ Ventura	Reliant	Attempt to site peaker at the Mandalay location is meeting local resistance
Mandalay	2	1959	YES	215	15	Ventura	Big Creek/ Ventura	Reliant	
Morro Bay	1	1956	YES	0	NA	San Luis Obispo		Dynegy/ LS Power	CEC issued permit in 2004 for replacement of the existing units with two new units that would continue to use OTC, relying on structures from old plants with habitat mitigation. Capacity increased to 1200 MW.
Morro Bay	2	1955	YES	0	NA	San Luis Obispo		Dynegy/ LS Power	
Morro Bay	3	1962	YES	338	11	San Luis Obispo		Dynegy/ LS Power	
Morro Bay	4	1963	YES	338	8	San Luis Obispo		Dynegy/ LS Power	
Moss Landing	1	1950	prev	116	68	Monterey		Dynegy/ LS Power	CEC issed permit in 2002 for new Units 1 & 2 equal 1060 MW replaced old units 1-5 (retired 1995) and uses once through cooling, contract through 2010
Moss Landing	2	1950	prev	115	71	Monterey		Dynegy/ LS Power	
Moss Landing	3	1951	prev	117	NA	Monterey		Dynegy/ LS Power	
Moss Landing	4	1952	prev	117	NA	Monterey		Dynegy/ LS Power	
Moss Landing	6	1967	YES	739	6	Monterey		Dynegy/ LS Power	Unit contingent tolling agreement with RA for 1509 MW
Moss Landing	7	1968	YES	739	10	Monterey		Dynegy/ LS Power	
Olive	1	1959	NO	46	1	Los Angeles		Burbank Water and Power	Retrofit in 2006, control systems upgraded. Used for load following and peaking. Expects to run until 2016
Olive	2	1964	NO	55	NA	Los Angeles		Burbank Water and Power	
Ormond Beach	1	1971	YES	750	5	Ventura	LA Basin	Reliant	
Ormond Beach	2	1973	YES	750	9	Ventura	LA Basin	Reliant	
Pittsburg	5	1960	YES	325	3	Contra Costa	Bay Area	Mirant	
Pittsburg	6	1961	YES	325	2	Contra Costa	Bay Area	Mirant	
Pittsburg	7	1972	YES	720	1	Contra Costa	Bay Area	Mirant	

Table 4. Aging and Once Through Cooling Power Plants

September 2008

Potrero	3	1965	YES	207	26	San Francisco	Bay Area	Mirant	AFC for repower of Unit 3 withdrawn. Alternate SF Reliabilty plan to allow shutdown of entire Potrero plant using distributed peakers has stalled. May locate City peakers at Potrero site
Redondo Beach	5	1954	YES	175	1	Los Angeles	LA Basin	AES Southland /Bear Energy	
Redondo Beach	6	1957	YES	175	2	Los Angeles	LA Basin	AES Southland /Bear Energy	
Redondo Beach	7	1967	YES	480	6	Los Angeles	LA Basin	AES Southland /Bear Energy	
Redondo Beach	8	1967	YES	480	4	Los Angeles	LA Basin	AES Southland /Bear Energy	
San Onofre	2	1983	YES	1086	84	San Diego	LA Basin	SCE/SDGE	Steam Generator Replacement project begins in 2009
San Onofre	3	1984	YES	1086	90	San Diego	LA Basin	SCE/SDGE	Steam Generator Replacement project begins in 2010
Scattergood	1	1939	YES	179	16	Los Angeles		LADWP	Part of Industrial complex. 2007 feasibility study done; project to include new CT, then evaluation of repower of Units 1 and 2 could go forward; Unit 3 problematic
Scattergood	2	1939	YES	179	25	Los Angeles		LADWP	
Scattergood	3	1939	YES	445	20	Los Angeles		LADWP	
South Bay	1	1960	YES	147	9	San Diego	San Diego	Dynegy/ LS Power	Application for repower withdrawn 2007
South Bay	2	1962	YES	150	10	San Diego	San Diego	Dynegy/ LS Power	
South Bay	3	1964	YES	171	13	San Diego	San Diego	Dynegy/ LS Power	
South Bay	4	1971	YES	222	8	San Diego	San Diego	Dynegy/ LS Power	

As for complying with SWRCB's proposal, owners are unlikely to opt for refitting, repowering, and replacing the plant in the absence of long-term contracts, as they could not guarantee recovery of their substantial investment. Retirement, on the other hand, will likely require the construction of a new plant, since many of the OTC plants are located in California ISO-designated local reliability areas (the Greater San Francisco Bay Area, Los Angeles basin, and San Diego).

New plants would have to be located in the same or nearby location, unless transmission upgrades allow them to be built elsewhere. However, a recent superior court ruling preventing the South Coast Air Quality Management District from using compliance emissions credits from its priority reserve may without further environmental analysis delay the construction of new conventional power plants that would be necessary to replace retired OTC plants in the Los Angeles basin.[97]

The Energy Commission, the CPUC, and the California ISO face a challenge in facilitating compliance with the SWRCB's rule quickly and at the least cost to ratepayers. The rule "in a least-cost fashion" requires that OTC plant owners have not only the "option" of retirement, but also of refitting, repowering, and so on, when these are lower-cost solutions for the ratepayer.

Because refitting, repowering, and associated permitting can take two years or more, plant owners must have the opportunity to bid for long-term contracts for energy and capacity products long before the SWRCB's compliance deadline. Transmission planning (to assess the extent to which transmission upgrades should substitute for local generation) and permitting require even longer lead times. Additional coordination will be required, since compliance options will require facilities to shut down, either partly or entirely, for prolonged periods while being modified. These shutdowns must be staggered to maintain system reliability.

Procurement and the Siting Process

Projects responding to a utility's RFO may be in various stages of development, ranging from those without permits to those that are fully operational. Projects in the earlier stages of development involve greater financial risk, primarily to the project owner, for bringing them to completion. Ultimately, however, the utility must consider both financial and reliability risks in evaluating bids. Unforeseen delays or project termination can affect system reliability and cost, either by requiring the procurement of replacement capacity at a late date, circumventing competitive procurement processes, or implementing more expensive solutions.

In evaluating bids, the utilities consider project viability, partly by considering the status of permits and certificate possession. For instance, PG&E listed the following project viability considerations in its April 1, 2008, All Source Long Term RFO (p. 14):

> "The project's progress in the [Energy Commission] permitting process will also be evaluated, including its Environmental Characteristics such as Air Quality, Water

97 The aging merchant facilities that rely on OTC in SCAQMD include Alamitos (1,950 MW), El Segundo (670 MW), Huntington Beach (Units 1-2, 430 MW), and Redondo Beach (1,310 MW).

> Supply, Land Use, Hazardous Material usage, Wetlands & other Waters, Biological Resources, Cultural Resources, Socioeconomics, degree of control of property, and other aspects that would help ensure project completion. The project's progress in the gas and electric interconnection processes will be evaluated. The quantities and potential costs to PG&E and to society associated with all of these characteristics will be considered."

Aside from these areas, there is no indication of how utilities evaluate progress in the permitting process, whether qualitatively or quantitatively, or how they rank projects that have not yet applied for permitting. In the past, some projects selected to receive contracts faced significant siting and environmental issues that threatened project viability, timely construction, and/or cost. In the best interest of utility shareholders and ratepayers, projects competing in an RFO should understand the siting-related criteria that will be used to judge them. In addition, projects should have a high probability of being permitted in the time frame required without major environmentally related modifications or cost increases.

Recommendations

Long-Term Procurement Planning

- The IEPR Committee recommends that staff continue collaborating in the CPUC's LTPP proceeding to develop 2010 plans that adequately consider the significant risks facing ratepayers, and to further develop useful assessments of GHG evaluation and uncertainty in the resource planning and procurement processes.

- The IEPR Committee recommends assessing longer-run (20-year) uncertainties related to electricity demand and natural gas prices and supply in the *2009 IEPR*. As the 2008 Procurement proceeding moves forward, other issues related to resource planning for the period beyond 2020 may warrant inclusion in the *2009 IEPR*. These issues include evaluating the development of gas-fired power plants to meet near-term reliability needs to minimize subsequent need for gas-fired resources, and exploring how to overcome constraints faced by utilities in reducing the carbon footprint of their portfolios over the long run.

- The IEPR Committee recommends that social discount rates not be used to incorporate natural gas price risks in the CPUC's current Rulemaking, but that the subject of using risk-adjusted discount rates to compare projects selected in utility solicitations be considered by the CPUC when making refinements in how to evaluate RFO bids in the LTPP proceeding.

Aging Plants and Once-Through Cooling Issues

Aging plant retirement, or repowering and transmission line upgrades, are subjects of an ongoing California ISO study to be completed in early 2009.[98] Additional analysis is needed on the implications of replacing much of the OTC capacity with preferred resources, such as

[98] See California Independent System Operator, Mitigating Mitigation of Reliance on Old Thermal Generation Including Those Using Once-Thru Cooling Systems Study Plan, http://www.caiso.com/1f52/1f529c671a380.pdf.

renewables, and gas-fired dispatchable generation to meet the need for local capacity and grid stability. Depending upon the ultimate scope and findings of the California ISO study, the following list contains possible topics for the *2009 IEPR*:

- Statistical assessment of relying on OTC and aging plants for energy and local capacity needs, including the Los Angeles basin.
- Summary of the California ISO study with issues and any obvious next steps, including (but not limited to) refining initial estimates of transmission costs for system expansion to allow OTC retirements, comparing transmission and generation costs and timeframes, devising a way to adapt a replacement plan as contingencies arise, and coordinating priorities among projects when multiple acceptable options exist.
- Examine power plant licensing and transmission line permitting issues.
- Interaction of OTC repowering/replacement/retirement and preferred resource development, system stability issues, and the potential of transmission upgrades to allow renewable capacity to replace OTC plants in transmission-constrained areas.
- Generator owners' reaction to SWRCB policy and the interaction among OTC policy, the procurement process, and the need for dispatchable conventional generation in local reliability areas.

Procurement and Siting

- The CPUC should take complete control of the procurement process and conduct a fully transparent method of ranking projects in the RFO bid evaluation phase that delineates how they consider project permitting. As part of the *2009 IEPR*, the Energy Commission will conduct a public process and invite the CPUC to help develop criteria for incorporating a project's progress in planning or permitting into the RFO bid evaluation.
- The siting-related criteria that are developed should apply to all projects that participate in an RFO, including those not under Energy Commission jurisdiction (under 50 MW or not thermally-based). The criteria should encompass all permitting issues that could result in project termination, delay, or cost increases. These should include, but not be limited to:
  - Accurate determination of Energy Commission jurisdiction, especially for projects just under the 50 MW threshold
  - Site control
  - Consistency with city or county general plan land use designations and zoning
  - Consistency with federal or state agency land use management plans
  - Land under a Williamson Act contract
  - Ability to obtain air permits
  - Use of best available air pollution control technology, as applicable
  - Availability or possession of adequate air pollution emission reduction credits, as applicable
  - Status of California ISO interconnection studies

- Use of cooling technologies that avoid the use of fresh water
- Site location outside of prohibited, restricted, or limited-use lands[99]
- Affect on listed or endangered species
- Use and storage of hazardous materials on site
- Size, locational preference, and other important procurement criteria

99 Wilderness areas or study areas, wildlife areas, wildlife management areas, wildlife refuges, roadless areas, ecological reserves, mitigation banks, habitat conservation areas, critical habitat areas for listed endangered and threatened species, species-specific conservation areas, state parks, Department of Defense lands, U.S. Forest Service lands, tribal lands.

CHAPTER 4: Assessment of California's Operating Nuclear Plants

Introduction

Assembly Bill 1632 (Blakeslee, Chapter 722, Statutes of 2006) directs the Energy Commission to assess the potential vulnerability of "large baseload generation facilities of 1,700 megawatts or greater" to a major disruption due to a seismic event or plant age-related issues. The Energy Commission is directed to adopt this assessment on or before November 1, 2008, and include it in the *2008 Integrated Energy Policy Report Update* (*2008 IEPR Update*). The AB 1632 assessment is an evolving analytical effort that is proceeding on a parallel track as described below. This chapter summarizes the information and findings to date from this assessment and will be revised to include specific recommendations as the AB 1632 assessment progresses.

The Energy Commission and its consultant, MRW & Associates, developed a study plan for the *AB 1632 Assessment of California's Operating Nuclear Plants* in January 2008 based on public input received at a December 2007 workshop. The Energy Commission released a draft consultant report for public comment on September 12, 2008, and held a public workshop on the report on September 25, 2008.[100]

After the September workshop, the Energy Commission's Electricity and Natural Gas Committee will develop its draft Committee report based on the consultant study and public comments received. The Energy Commission will release the draft Committee Report in October and hold a public workshop on the report in late October. The Energy Commission expects to adopt the final *AB 1632 Assessment of California's Operating Nuclear Plants* in November 2008, and the final findings and recommendations from that report will be included in the adopted *2008 IEPR Update*.

California's two operating nuclear facilities, the Diablo Canyon Power Plant (Diablo Canyon) and the San Onofre Nuclear Generating Station (SONGS), fall under the AB 1632 requirement. Although two natural-gas fired facilities, Alamitos and Moss Landing, have a nameplate capacity greater than 1,700 MW, both of these facilities operate below a 60 percent capacity factor and are therefore not considered baseload facilities and not included in the AB 1632 assessment.

AB 1632 also directed the Energy Commission to assess the impacts of a major disruption on system reliability, public safety, and the economy; to assess the costs and impacts from nuclear waste accumulating at these plants; and to evaluate other major issues related to the future role of these plants in the state's energy portfolio.

100 MRW & Associates, September 2008, *AB 1632 Assessment of California's Operating Nuclear Plants*, draft consultant report, http://www.energy.ca.gov/2008publications/CEC-100-2008-005/CEC-100-2008-005-D.PDF.

Diablo Canyon and SONGS represent 12 percent of California's overall electricity supply.[101] A major disruption because of an earthquake or plant aging could result in a shutdown of several months up to more than a year or even cause the retirement of one or more of the plants' reactors. Because these plants are so important to the state's electricity supply, California needs a long-term plan should such a disruption occur.

The U.S. Nuclear Regulatory Commission regulates commercial nuclear power plants, while the California Public Utilities Commission oversees the annual revenue required for each plant's decommissioning trust fund and determines revenue requirements for major capital projects at the plants. The AB 1632 analytical effort was designed to fill current gaps in the public record regarding five major issues associated with California's nuclear plants: seismic issues, age-related plant degradation; waste accumulation, transport, storage and disposal; reliability, cost, and environmental issues with respect to replacement power; and future consideration regarding plant license renewal.

Seismic Vulnerability Assessment

The assessment of seismic vulnerability looked at seismic hazards, tsunami hazards, power plant buildings and structures, spent fuel storage facilities, and roadways and transmission systems.

Seismic Hazards

The primary seismic hazard at Diablo Canyon is the offshore Hosgri Fault zone. There is some scientific disagreement on whether this fault is a lateral strike-slip fault or a thrust fault. A strike-slip fault is more vertically inclined, and a thrust fault has a shallower angle and extends diagonally beneath the surface. If the Hosgri Fault were a thrust fault with an eastward dip, the fault would extend closer to the Diablo Canyon site, and the ground motion resulting from an earthquake could be greater. The Diablo Canyon seismic setting has been extensively studied, largely under the Long-Term Seismic Program,[97] and further study using advanced technology may help resolve the Hosgri Fault debate.

PG&E evaluated the seismic hazard at Diablo Canyon from the Hosgri Fault for probabilities of 67 percent strike-slip faulting and 33 percent thrust faulting. PG&E found that there was sufficient safety margin in the plant design to accommodate the resulting ground motion, even though this motion was greater than had been anticipated when the plant was designed.

Another potential seismic hazard at Diablo Canyon is the possibility of an earthquake directly beneath the plant. In 2003, the San Simeon earthquake occurred about 35 miles north of the Diablo Canyon site, and the tectonic setting of Diablo Canyon appears to be similar in part to where that earthquake occurred. The deep geometry of faults where Diablo Canyon sits is not well enough understood to rule out a San Simeon-type earthquake directly beneath the plant.

---

101 California Energy Commission, *2007 Net System Power Report*, April 2008. pp. 4-5. http://www.energy.ca.gov/2008publications/CEC-200-2008-002/CEC-200-2008-002-CMF.PDF.

Improved characterizations of these fault zones would refine estimates of the ground motion that is likely to occur at different frequencies. This information would be significant for engineering vulnerability assessments.

Finally, characteristics of ground motions that could result from earthquakes is an area of continuing research. Recent studies have found that ground motion in close proximity to a fault could be stronger and more variable than previously thought. This could be important at Diablo Canyon since the plant lies within eight kilometers of the Hosgri Fault.

In contrast to the Diablo Canyon site, a recent review by the California Coastal Commission in connection with the construction of a proposed spent fuel storage facility states "there is credible reason to believe that the design basis earthquake approved by U.S. Nuclear Regulatory Commission (NRC) at the time of the licensing of SONGS 2 and 3 … may underestimate the seismic risk at the site."[102]

As newer data become available, the emerging concern appears to be an eroding safety margin at the SONGS site. The estimated frequency of a design basis ("safe shutdown") earthquake decreased from 1 in 7,194 years in a 1995 study to 1 in 5,747 years in a 2001 study. Because the plant was engineered with a large margin of safety, it will likely withstand earthquakes of greater magnitude and frequency than originally expected. However, the possibility that the safety margin is shrinking suggests that further study is necessary to characterize the seismic hazard at the site, especially since much less is known about the seismic setting of SONGS than the seismic setting of Diablo Canyon. There is no program at SONGS similar to PG&E's Long-Term Seismic Program at Diablo Canyon.

Like Diablo Canyon, SONGS is located within 10 kilometers of a fault, and new research on ground motion near an earthquake rupture is relevant to the seismic hazard of the plant. When SCE incorporated some of these developments into the seismic hazard assessment for SONGS, SCE found that the safety margins at the plant are less than previously believed.

Tsunami Hazards at Diablo Canyon and SONGS

PG&E is reassessing the tsunami hazard at Diablo Canyon. The most recent study in early 1990s concluded that the plant was designed to sustain the largest tsunami that can be expected at the site. However, it appears that SCE has not reassessed the tsunami hazard at SONGS since the plant was designed. Since then, scientists have learned that submarine landslides can generate large local tsunamis. Tsunami run-up maps that are being prepared by the University of Southern California will incorporate expected hazards from such near-to-shore landslides. Currently, it is not possible to determine whether these new maps will result in significantly revised estimates of the tsunami hazard at SONGS, but even a moderate increase in the estimated maximum tsunami run-up could raise significant concerns about the adequacy of the site's seawall.

---

102 California Coastal Commission, http://www.coastal.ca.gov/energy/E-00-014-3mmi.pdf, page 19.

For both plants, there are recently developed tools that could more accurately assess current tsunami hazards. Probabilistic hazard assessments, inundation modeling, and data from the National Oceanic and Atmospheric Administration's Short-Term Inundation Forecast for Tsunamis system could improve the quality of future assessments.

Vulnerability of Power Plant Buildings and Structures

The safety-related systems, structures, and components of Diablo Canyon and SONGS are designed to remain safe during safe-shutdown earthquakes of magnitude 7.5 on the Hosgri Fault and 7.0 on the South Coast Offshore Fault Zone, respectively. These earthquakes are expected to be the largest that could impact the plants given what is currently known about the geology of local faults.

The largest earthquakes experienced at SONGS and Diablo Canyon have been significantly less than the plants' safe-shutdown earthquakes, which could cause serious damage to Diablo Canyon or SONGS with the damage centered on the non-nuclear areas of the plants. The safety-related portions of the plants—the reactor, primary steam supply, containment, and associated equipment—are expected to withstand safe-shutdown earthquakes without damage that would impact safety.

Plant switchyards are particularly vulnerable to ground motion and earthquake damage. The degree of damage will depend on the extent to which SCE and PG&E have upgraded their plants' switchyard equipment to meet the newest seismic design standards. Failure of a switchyard could result in a loss of power from the plants even if the reactor units remain safe and undamaged.

The turbine building and tank areas could also be susceptible to damage. The turbine building at Diablo Canyon is large with an expansive open space inside, and the roof could collapse in an earthquake. At SONGS, the condensate storage tank and the refueling water storage tank are in low-lying areas that could sustain water damage in the event of a tsunami, while ground movement near the support pads for the tanks could cause underground pipes to burst and damage the tanks.

Following an earthquake, Diablo Canyon or SONGS could be shut down for as little as one week to as much as four years for repairs or component replacement. Estimates of time to repair or replace nuclear plant components are very uncertain. Other factors affecting the duration of a shutdown include the amount of time needed to investigate the plant for damage and the need for design and backfitting efforts. Public or regulatory concerns also could delay the restart of the power plant.

There are lessons to be learned from the effects of the 2007 Niigata Chuetsu-Oki earthquake on the Kashiwazaki-Kariwa Nuclear Power Plant. That facility experienced ground motions significantly higher than the design basis but suffered no significant damage to safety-related components. Nevertheless, more than a year after the earthquake, the facility remains shut down, apparently because of extensive investigations. This suggests that repairing or replacing damaged components may not be the primary driver of how long a nuclear power plant is shut down following a major seismic event.

Vulnerability of Spent Fuel Storage Facilities

There are two general types of spent ("used") nuclear fuel storage, pool and dry cask storage. Diablo Canyon and SONGS currently use pools for spent fuel storage; however, dry cask storage facilities have also been built for the increasing amount of spent fuel stored on site. The greatest risk for spent fuel pools is the loss of water or the loss of active cooling. Such an event could result in overheating of the stored spent fuel and release of radioactive material. The design of spent fuel storage pools reduces the possibility of water loss to levels lower than the stored fuel, but the loss of any amount of water is undesirable. The spent fuel pools at Diablo Canyon and SONGS are supported on or partially embedded in the ground to increase their ability to withstand seismic ground motion beyond their design basis.

Because of the lack of a permanent spent fuel disposal facility, the spent fuel pools at Diablo Canyon and SONGS have been modified to provide increased storage capability. The more densely configured spent fuel pools are thought to have a higher degree of risk, and loss of coolant in these densely configured pools could result in extensive radiation release and contamination.

An earthquake or other impact to a spent fuel pool could result in the spread of radioactivity if contaminated water spills from the pool, as occurred during the July 2007 Niigata Chuetsu-Oki earthquake in Japan. Spilled water in one reactor building leaked into the Sea of Japan from leaks in the reactor building floor. Although the SONGS and Diablo Canyon spent fuel pools are designed to curb the effects of sloshing, PG&E is investigating the water-tightness of conduits in its reactor buildings.

In general, a dry cask storage facility is considered to have a lower degree of overall risk than a spent fuel pool. Over the last 20 years, there have been no radiation releases from a dry cask storage facility that have affected the public, no radioactive contamination, and no known or suspected attempts of sabotage. A major study on the risks of dry cask storage by Robert Alvarez, a Senior Scholar of Nuclear Policy at the Institute for Policy Studies, suggested that the use of dry cask storage at a nuclear power plant has the potential to reduce the overall risk associated with at-reactor storage of spent fuel, including the risk of seismic and terrorist events, since dry cask storage would allow the spent fuel pools to be returned to their original configuration and design loading.

Risk analyses by the NRC and the Electric Power Research Institute concluded that cask loading and transportation, which occur primarily during the first year of operation, pose a greater risk of an event leading to public harm because spent fuel is exposed and in motion, which increases the possibility for accidents.

Diablo Canyon's dry cask storage facility incorporated a number of seismic safety features after an analysis of near-source fault ruptures. The SONGS dry cask storage facility was built to higher-than-required seismic standards. In reviewing the SONGS facility's seismic design, the California Coastal Commission concluded that even an earthquake much larger or closer than the design earthquake would not produce ground shaking that would exceed the design of the facility.

The AB 1632 study also reviewed published risk analyses for terrorist events or sabotage at dry cask storage facilities. Limited information is available on the vulnerability of dry cask storage to sabotage, which is consistent with the National Academies' finding when it conducted a study of spent fuel storage safety. While terrorist scenarios have been postulated that could release a significant amount of cesium into the environment, an assessment of the likelihood of such scenarios occurring has not been publicly released.

Vulnerability of Roadways and Transmission Systems

The main concern with seismic vulnerability of roadways serving Diablo Canyon and SONGS is the ability for emergency personnel to reach the plants and for the local community and plant workers to evacuate. Diablo Canyon is served by a two-lane asphalt road, and during an emergency, this could result in traffic congestion and increase the potential for traffic accidents and further congestion. At SONGS, access roadways have a large capacity to bring in emergency supplies and relief personnel, but if the emergency impacts nearby residents there could be congestion from traffic traveling through this corridor to escape a threatening situation. If the traffic overwhelmed the highway system, it could halt highway access and impede emergency response.

The distributed nature of the transmission system makes the transmission system relatively more vulnerable than a nuclear plant to terrorist attack, but such an attack would not result in high human or environmental risk. Transmission towers and poles are not very susceptible to earthquake damage. However, as discussed above, switchyards are likely to be damaged during large earthquakes.

Aging Plant Issues

As any power plant ages, there is a continuous trade-off between investing in plant maintenance, upgrades, and staffing and the benefits of keeping the plants running. Nuclear plants are the most complex types of electricity generation plants, and due to their large size, high capital costs and nuclear fuel, their plant performance needs to be held to a high standard. Many components can be at risk, including not just the nuclear components, but also the pumps, emergency systems, and electrical systems. California's nuclear plants are approaching their fourth decade of operation and are subject to age-related degradation that could lead to a loss of function and impaired safety if not addressed. Effective maintenance programs and regulatory oversight are essential in identifying aging plant equipment and components to ensure that they are repaired or replaced to maintain plant reliability and safety. Failure to do so could have major long-term implications.

Nuclear plants are baseload units and are planned to operate as much as possible. The standard measurement of nuclear plant performance is the capacity factor, which is calculated by dividing how much energy a plant actually generates by the total possible energy produced during a given period. Reduced capacity factors over time may indicate age-related degradation. Capacity factors at Diablo Canyon and SONGS have actually increased since the early years of plant operation, and both plants achieved five-year average capacity factors of approximately 90 percent.[103] This does not necessarily indicate the absence of plant degradation; improved plant operations including reduced down time for plant maintenance and refueling may have compensated for possible degradation.

Not all nuclear plants have similar track records. Nuclear plants outside of California like Davis-Besse (Ohio), Vermont Yankee (Vermont), Oyster Creek (New Jersey), and Indian Point (New York) have all received increased scrutiny by the NRC, government agencies, and/or watchdog groups concerned that different types of age-related degradation are eroding the safety of the plants. The implications for Diablo Canyon and SONGS are twofold. First, the same unanticipated age-related degradation of some plant component or system could be occurring at the California plants. Second, a serious incident or a safety hazard at one plant could result in a regulatory requirement for more extensive inspections, repairs, and even outages at similar plants nationwide.

Maintenance plays a central role in reducing age-related degradation and failure of components. A strong safety culture (that is, a strong "safety-first" dedication and accountability among plant workers) is a key element of an effective maintenance program, and problems with safety culture have been linked to the high-profile operational difficulties at the Palo Verde Nuclear Generation Station in Arizona and the extensive reactor vessel degradation uncovered at the Davis-Besse plant. All units at Diablo Canyon and SONGS have achieved the highest level of the NRC's maintenance-related performance indicators since the second quarter of 2006, when a new performance-tracking system was initiated. However, the NRC has raised concerns about the safety culture at SONGS and as a result has required SCE to create a plan to improve the safety culture at the plant. Diablo Canyon has had no NRC violations since 1995 and appears to have a relatively effective safety culture. In this regard, Diablo Canyon benefits from the oversight of the Diablo Canyon Independent Safety Commission, which investigates concerns that do arise. One of the recommendations of this study is that SONGS would benefit from an analogous independent safety oversight committee.

As the workforces at Diablo Canyon and SONGS age, large numbers of employees will soon retire. Both PG&E and SCE have instituted programs to replace retiring workers and to pass on their institutional knowledge. It is critical to the ongoing reliability and safety of the plant that they do so and that strong safety cultures are maintained throughout this shift in workforce.

103 California Energy Commission, *Nuclear Power in California: Status Report 2007*, October 2007, http://www.energy.ca.gov/2007publications/CEC-100-2007-005/CEC-100-2007-005-F.PDF.

Nuclear Waste Disposal and Storage Issues

Diablo Canyon and SONGS produce significant quantities of radioactive waste in the form of spent fuel and other radioactively contaminated materials. These wastes must be carefully handled, stored, transported, and disposed of to protect humans and the environment from exposure to radioactive materials.

High-Level Radioactive Waste

Spent nuclear fuel or "used" fuel is extremely radioactive, and fuel assemblies must be stored in a water-filled pool for a minimum of five years following removal from the reactor core to shield against high levels of radiation. Once the spent fuel has cooled somewhat, it can be left in the pool or be moved to dry cask storage facilities consisting of metal or concrete outer shells with inner sealed metal cylinders that contain the spent fuel. Loaded casks are stored on concrete storage pads in an on-site area away from the reactors.

In June 2008, DOE filed a license application for a permanent geologic repository for spent fuel at Yucca Mountain, Nevada. If the license is granted, Yucca Mountain will begin operations sometime after 2020. In the absence of a permanent repository for spent fuel, utilities are using dry cask storage as an interim solution for waste disposal. Between spent fuel pool and dry cask storage, dry casks are generally considered to be the safer form. Over the last 20 years, there have been no radiation releases from a dry cask storage facility that have affected the public, no radioactive contamination, and no known or suspected attempts to sabotage spent fuel casks.

PG&E and SCE have taken different approaches for the design and use of dry cask storage facilities at Diablo Canyon and SONGS. At Diablo Canyon, PG&E has designed and permitted dry cask storage that will allow PG&E to transfer and store 100 percent of the spent fuel produced during the period of the current operating license. This approach would allow PG&E to decommission Diablo Canyon's spent fuel pool at the end of the current license if needed.

In contrast, SCE has designed dry cask storage with a capacity to store only 36 percent of the spent fuel generated during the current license period, and intends to rely on its spent fuel pool to store the remaining spent fuel. Additional storage space would be required if SONGS were to continue operating past its current license or if SCE wished to decommission the SONGS spent fuel pools before the availability of off-site spent fuel storage. Moreover, the total combined storage capacity at SONGS is just 98 percent of the total spent fuel expected to be produced during the plant's current operating license. To accommodate the remaining spent fuel, SCE will need to secure offsite storage or develop additional capacity. SCE has not yet determined how it will manage the extra spent fuel.

The costs for constructing and loading dry cask storage are substantial. On a present value basis, the total cost is $160 million for Diablo Canyon and $300 million for SONGS. With dry cask storage at SONGS 40 percent the size of the storage at Diablo Canyon facility and nearly twice as expensive, storage at SONGS is three to four times as expensive per fuel assembly.

PG&E's dry cask storage is designed for a lifetime of 50 years, and SCE's for a lifetime of 40 years. If the spent fuel is not transported off-site within the design lives of the dry cask storage system components, the spent fuel may need to be repackaged on-site and transferred into new storage canisters, or the current canisters or other storage system components may need to be bolstered. At this time there are no estimates how long the spent fuel will remain in interim dry-cask storage, and no additional off-site or on-site interim fuel storage facilities are being considered by either PG&E or SCE.

If a federal repository is established, the DOE plans to develop a spent fuel packaging system for the transport, aging, and disposal of spent fuel. The federal packaging requirements have not yet been established, forcing PG&E and SCE to move forward with onsite dry storage cask designs that may not be compatible with the federal canister requirements. In addition, costs for transport of spent fuel to off-site storage or disposal facilities will be substantial, including costs for security, accident prevention, and emergency preparedness. Policies are being developed for federal funding of state and county emergency response preparation costs; however, California has claimed that the proposed federal program is insufficient, both in the planned timing of the grant program and the amount of the proposed grants for planning and for training emergency personnel to respond to potential accidents involving spent fuel shipments.

There is considerable uncertainty about if and when a geologic repository or other interim waste storage facility will allow the removal of spent fuel from the Diablo Canyon and SONGS plant sites. This uncertainty raises questions about the land use and economic implications of extended on-site waste storage for these localities. The concern is that long-term storage of spent fuel at the plant sites could have a negative effect on future land uses, local property values, business, and tourism because of health and safety risks.

The experience of several communities where nuclear power plants have been shut down and decommissioned but a dry cask storage facility remains does not support this concern. Local communities near California's Rancho Seco nuclear power plant and Maine's Yankee nuclear power plant have successfully converted the land and the area immediately around it into recreational or economically productive mixed use properties. The Connecticut Yankee nuclear plant site may also soon be developed.

Accordingly, the presence of dry cask storage facilities at Diablo Canyon and SONGS after the plants are decommissioned need not prevent alternate uses from being established. In the case of Diablo Canyon, the plant site will likely be converted to primarily recreational use. In the case of SONGS, the plant site, which is located on military land, will presumably remain under the control of the U.S. Navy. The Navy will have the option to use the land for military purposes, lease or sell to another party, or open it for recreational use.

Even for plant sites converted to alternate uses, the question remains whether the continued presence of the spent fuel has a negative impact on property values, business, and tourism in the area. Academic research does not lead to a strong conclusion that a dry cask storage facility would negatively affect nearby property values. However, the available analytical studies are extremely limited and only partially relevant, and the available surveys appear to be unreliable predictors of economic effects. An analysis of property sales data and other economic indicators in areas where a dry cask storage facility is operating would provide a useful starting point to assess potential economic impacts of extended spent fuel storage at California's nuclear plant.

Low-Level Radioactive Waste

Low-level radioactive waste also requires care in handling, transport, and disposal. There are only two facilities in the United States that accept low-level waste for disposal and only one that accepts waste from California. As of June 30, 2008, the facility in South Carolina accepts only low-level waste from South Carolina, Connecticut, and New Jersey. That leaves the Energy Solutions facility in Clive, Utah, as the only facility available to accept low-level waste from Diablo Canyon and SONGS. It is expected that Class A waste will continue to be shipped to Clive, Utah. The NRC is reviewing its policies regarding on-site low-level waste storage and expects to complete this task by the end of 2008.

Low-level waste disposal costs are relatively modest during ongoing plant operations. However, a substantial quantity of low-level waste will need to be disposed of when the plants are decommissioned, and the cost to transport and dispose of this waste, presuming a disposal facility is available, is expected to be hundreds of millions of dollars, if not more. Low-level waste disposal costs have been rising in recent years, and current estimates of disposal costs during decommissioning are based on outdated cost information. Costs could be substantially higher than estimated during the most recent California regulatory proceeding on decommissioning costs.

Replacement Power Issues

An earthquake, age-related plant or equipment failure, or other events could lead to one or both of California's nuclear plants going off-line for extended periods. Actions at other plants and not directly related to the in-state nuclear plants could also result in a shutdown. For example, a major safety-related event at a nuclear power plant elsewhere in the country could lead to a general shutdown of other nuclear plants for an indefinite period.

In such an event, the power from the impaired units would need to be replaced with power from other sources. The reliability, cost, and environmental implications of using replacement power would depend on what time of year the outage occurred and what replacement power was available. PG&E and SCE generally schedule refueling outages and other maintenance shutdowns to avoid periods of peak demand and reduce the cost of replacement power. Unplanned outages, however, can occur at any time. The experiences of nuclear plants nationwide indicate that while most unplanned outages last just a few days, many reactors have outages lasting a year or longer, mostly because of component degradation.

Reliability Implications

To assess replacement power options in the event of a lengthy, unplanned outage at one or both of the nuclear plants, the study team simulated the operations of the electricity market for 2012 with and without one or both of the nuclear plants. The simulations suggest that no generation supply shortages would occur as the result of either Diablo Canyon or SONGS being unexpectedly off-line for an extended period in 2012, nor would remedial action, such as additional demand response, energy efficiency, or additional capacity, be needed for reliability purposes. Based on simulations, replacement power in the event of a year-long outage at Diablo Canyon or SONGS in 2012, the replacement power would be supplied mostly by combined-cycle gas-fired plants. Approximately 55 to 62 percent of the increased generation would come from in-state gas-fired plants, while the remainder would come from out-of-state gas-fired plants along with a small amount of increased coal generation. The California Independent System Operator has a similar finding which shows sufficient reserve margins to accommodate the temporary loss of either or both nuclear plants.

Regarding transmission, previous studies have shown that while Diablo Canyon represents a significant generation resource and supports power flows through Path 15 and Path 26, the plant is not needed to maintain reliable operation of the transmission system. During a major disruption at Diablo Canyon, replacement power can be supplied by existing and new resources, albeit at significant cost and with a greater impact on the environment since most of the replacement power would come from gas-fired plants. SONGS appears to be a more integral part of the Southern California transmission system. SONGS supports the bulk transmission system, and when it is shut down, imported power flows are also restricted. Although replacement generation would be available (at similar costs and environmental impact as those for Diablo Canyon), a prolonged shutdown of SONGS could result in serious electricity shortfalls without transmission system infrastructure improvements. The extent of the transmission system changes would depend on the transmission configuration in place at the time of the SONGS shutdown.

This quick look at near-term replacement vulnerabilities is not applicable to the post-2012 period. More complete studies will be needed periodically to reassess the availability of replacement power given updated supply and demand conditions. Additional modeling would be needed to determine the implications on the grid of permanently retiring Diablo Canyon and SONGS after 2012.

Cost Implications

The cost of replacement power would include the operating costs of in-state units and market costs to acquire power from out-of-state.[104] For a yearlong loss of either Diablo Canyon or SONGS, simulations indicate that costs would be $470 million higher than the cost to generate power from the nuclear plant. This would increase average rates for customers of either PG&E or SCE/SDG&E by approximately 0.5¢ per kilowatt-hour (kWh) while the outage continued. Plant repair costs would further increase rates.

104 The modeling assumes that incremental power from in-state resources can be acquired at the cost of service (that is, are owned by the utilities or under a tolling contract) while incremental power from out of state must be purchased at market rates calculated internally within the MARKETSYM model.

Environmental Implications

An outage of either Diablo Canyon or SONGS will also pose environmental consequences, since the replacement power would be largely fossil-fueled. The simulations found that an outage at either nuclear plant would increase in-state greenhouse gas emissions from power generation by 7 to 8 percent, or roughly 4.3 to 4.7 million tons of carbon dioxide (CO_2). Out-of-state replacement generation would add an additional 2.2 to 2.8 million tons of CO_2, for a total greenhouse gas impact of approximately 7 million tons of CO_2.

If the only concern was replacing the energy from these units, given adequate time to license and build new units, California could build new renewable generation to meet its electricity demand. But, since many large-scale renewable units do not have the same operational characteristics as baseload nuclear units, current technologies would likely require support of some fossil units to replace all the attributes of Diablo Canyon and SONGS. Operational and local transmission issues must be studied more carefully to identify which attributes of these plants need to be replicated should a long-term shutdown occur.

Neither nuclear power nor renewable energy sources of power are free of environmental impacts. A comparison of the life cycle greenhouse gas emissions for nuclear power, wind, solar photovoltaic, geothermal, and biomass shows that these technologies have comparable levels of life cycle greenhouse gas emissions.[105] Additional environmental impacts from nuclear energy generation include the risks from a major plant accident or terrorist event, as well as nuclear waste storage, transport, and disposal issues. If an accident or attack leads to a propagating spent fuel fire at the nuclear power plant, it could result in the release of large amounts of radioactive material. The consequences of such an event could impact surrounding populations, farmland, and ecosystems.

To serve as substitutes, renewable power would have to be supplemented with fossil-fired generation, and all of these units would have their own environmental impacts. However, because life cycle analyses often use widely varying methods and assumptions and, in many cases, limited data, care must be taken to interpret the results of such analyses in light of these limitations. Additional modeling will be needed to fully understand the environmental tradeoffs of permanently retiring Diablo Canyon and SONGS.

Local economic impacts of generating facilities can also be important factors in policy decisions about resource options. Replacing the nuclear plants with an equal mixture of in-state wind, solar thermal, geothermal, and biomass power along with its fossil-fired supplements would result in roughly the same overall tax and employment benefits to the state as provided by the nuclear plants.[106] However, these benefits would be conferred to different localities. The communities currently benefiting from the nuclear plants would lose jobs and revenue unless the nuclear plants were replaced by other income-generating facilities. The loss of the plants

---

105 MRW & Associates, Inc., *AB 1632 Assessment of California's Operating Nuclear Plants*, draft consultant report, July 2008, Appendix B.

106 Ibid, p. 224.

would mean the loss of high-paying jobs and tax revenues. This loss would be felt more strongly in San Luis Obispo County following the closure of Diablo Canyon than it would be in the much-larger San Diego and Orange Counties following the closure of SONGS. Some or all of this loss could be recouped over time by the use of the reclaimed land for other income-generating enterprises. It is also possible that some of this loss could by offset by a rise in property values, if current property values are depressed by the presence of the plants. However, additional study is required to assess whether this is the case and whether the closure of the plants would reverse this impact, especially if nuclear waste remains on-site.

License Renewal Issues

Diablo Canyon and SONGS have been operating for roughly half of their 40-year initial license periods, and PG&E and SCE are exploring the feasibility of seeking 20-year license renewals from the U.S. NRC for the plants. If granted, license renewals could keep Diablo Canyon and SONGS in operation until the early- to mid-2040s.

The operating license for Diablo Canyon Unit 1 expires in 2024 and for Unit 2 expires in 2025, and the operating licenses for San Onofre Nuclear Generating Station Units 2 and 3 expire in 2022. Although there is no limit on how late a licensee may apply for license renewal, if a nuclear power plant licensee applies for renewal at least five years before the expiration of its current operating license and the NRC is still reviewing the application at the end of five years, the plant can continue to operate beyond its license expiration until the NRC completes its review. The studies that have been undertaken in the *AB 1632 Assessment of California's Operating Nuclear Plants* are designed to contribute to the license renewal foundational analysis. The ultimate decision whether to renew the Diablo Canyon and SONGS operating licenses will have a significant effect on the state's power supply portfolio and on the communities located near the reactors in the decade after next.

The cost of power from these plants over the license renewal period will be linked to the performance of the plants. If the plants maintain high levels of performance and safety and do not require significant repairs, the costs could remain comparable to current levels with relatively minor increases due to higher nuclear fuel costs and potentially stricter security requirements. However, degradation of major components or extended outages could result in much higher costs. In addition, the plants may be required to retrofit their once-through cooling systems before a license renewal. The retrofit and outage are expected to cost a net present value of $2.6 billion at SONGS and $3.0 billion at Diablo Canyon.

In addition, it is important to consider the environmental impacts from plant operations over an extended 20-year license period, including once-through cooling ocean impacts and impacts from continuing waste accumulation at these plants. The extent of the impacts will depend on the outcomes of state and federal policies and requirements for once-through cooling and on whether a long-term solution to the waste disposal problem is found.

The impact that shutting down one or both of the plants would have on the reliability of California's electricity grid is unclear at this time. The impact will depend on what other generating and transmission resources are built or retired over the next two decades and on the pattern of population growth in the regions near the plants. This is an area that needs to be investigated further before any decision on license renewal.

Findings

Seismic Vulnerability

- PG&E has explored the seismology and geology of the Diablo Canyon site, but much less is known about the SONGS seismic setting. New information on ground motion and blind thrust faulting has eroded the perceived safety margins of SONGS. Further investigation of the vulnerability of the plant to seismic hazards is needed.

- Uncertainties exist regarding the regional tectonic setting surrounding Diablo Canyon and the nature of the Hosgri Fault. Current published data support the interpretation that the Hosgri Fault is a strike-slip fault, but another model considers the Hosgri Fault a thrust fault. If it is a thrust fault, the seismic hazard at Diablo Canyon could be greater than currently anticipated.

- Diablo Canyon is located within the San Luis-Pismo geologic block. There is a need to better define the deep geometry of bounding faults of this block and to better understand the lateral continuity of these fault zones. Although the Hosgri Fault is the dominant source of seismic hazard at Diablo Canyon, improved characterizations of other fault zones are needed to better estimate likely ground motion. This would be significant for future engineering vulnerability assessments.

- An earthquake directly beneath Diablo Canyon of similar nature to the 2003 San Simeon earthquake cannot be conclusively ruled out. Analysis of this possibility should include the expected ground motions and vulnerabilities of plant components that might be sensitive to pulse-type, long-period motions in the near field of an earthquake rupture.

- Future study with newer technologies, such as three-dimensional geophysical seismic reflection mapping, could resolve questions about the characterization of the Hosgri Fault and might change estimates of the seismic hazard at the plant. Similarly, such imaging at strategically chosen locations could serve to prove or disprove the existence of subsurface faults in the San Luis–Pismo tectonic block and could also serve to refine knowledge of the deep geometry, continuity, and interaction of poorly expressed faults that comprise the structural boundaries of the San Luis–Pismo Block.

- Establishment of a permanent global positioning system array in the onshore region of the Diablo Canyon site could clarify the nature of local crustal movements through repeated surveys. Results of these surveys might alter fault parameters that are used in existing seismic hazard assessments.

- The major uncertainties regarding the seismology of the SONGS site relate to the continuity, structure, and earthquake potential of a nearby offshore fault zone that connects faults in the

Los Angeles and San Diego regions. There is also uncertainty regarding the potential for unknown faults near the plant. Well-planned, high-quality three-dimensional seismic reflection data at strategically chosen locations may resolve many of the remaining uncertainties and might change current estimates of the seismic hazard at the plant.

- New seismologic and geologic information that has emerged since SONGS was built indicates that SONGS could experience larger ground motions from earthquakes than had been anticipated at the time the plant was designed. This does not necessarily imply that the plant is unsafe; however, it raises safety and reliability concerns that warrant further study.
- In the years since Diablo Canyon and SONGS were built, scientists have learned more about the ground motions that could result from an earthquake rupture. One important finding is that ground motion can be highly variable in the region near a rupture, with amplified ground motion in some areas. These effects have already contributed to a higher revised seismic hazard assessment at SONGS. It will be important for PG&E and SCE to continue to evaluate the implications of new approaches to incorporating estimates of ground motion variability in the near-source region of faults.
- The U.S. Geological Survey (USGS), California Geological Survey, and the Southern California Earthquake Center have developed a detailed, updated database of faults and rupture probabilities in California. This database, along with USGS models, would provide additional useful information regarding the seismic hazards at Diablo Canyon and SONGS. To obtain accurate seismic hazard data, the USGS models must be modified to reflect site-specific conditions at the plants.
- In addition to the direct hazard from earthquake ground motion, there are secondary seismic hazards that could impact the nuclear plants. Liquefaction and landslides do not appear to be significant hazards at Diablo Canyon or SONGS. There is less certainty regarding the tsunami hazards at the sites because currently available tsunami studies for both plants are at least 10 years old and do not take advantage of modern tools that could improve the quality of the assessments.
- Updated tsunami hazard assessments are important for both plants, but they are more critical for SONGS. This is because the SONGS seawall is just three feet higher than the largest tsunami that was thought to be possible at the site based on the original tsunami hazard studies conducted during the plant's design. These studies did not consider the hazard from submarine landslides, which could be large events. PG&E is reassessing the tsunami hazard at Diablo Canyon; SCE is not planning a reassessment of the tsunami hazard at SONGS.
- The non-safety related systems, structures, and components of the plants are the greatest sources of seismic-related vulnerability for SONGS and Diablo Canyon. The electrical switchyards are particularly vulnerable to damage. Damage to these systems would not pose a safety hazard to the public but could result in outages of weeks or months for repairs.

- A full understanding of the vulnerability of Diablo Canyon and SONGS to a major disruption of operations as a result of seismic events is incomplete without an analysis of the implications of seismic design changes that have occurred since these plants were designed and built. Such an analysis would need to consider any retrofits that PG&E and SCE may have undertaken.

- The estimated times to repair or replace components within a nuclear power plant may range from one week to as much as several years. The determining factor most likely would be the location of the damage, that is, whether the repair is on the nuclear side or the non-nuclear side of the power plant, but plant shutdowns are not only tied to equipment repair times but also can be driven by regulatory and political concerns.

- The spent fuel pools and dry cask storage facilities at Diablo Canyon and SONGS have been designed to sustain a design basis ("safe shutdown") earthquake at the plants, and they are unlikely to fail due to an earthquake. In addition, the dry cask storage facilities were built to accommodate newly characterized effects that can amplify earthquake ground motion and that could impact the seismic hazard of the facilities.

Plant Aging and Reliability

- Aging plant components must be adequately monitored, maintained, and repaired to have a safe and reliable nuclear power supply. Unchecked age-related degradation could have significant long-term implications for safety and plant reliability.

- Effective maintenance and a strong safety culture are critical to keeping Diablo Canyon and SONGS operating safely and reliably. The NRC has raised concerns about the safety culture at SONGS and has required SCE to create a plan to improve safety culture at the plant. Diablo Canyon appears to have a relatively effective safety culture and benefits from the oversight of the Diablo Canyon Independent Safety Committee. There is no similar independent safety oversight committee for SONGS.

- The workforces at Diablo Canyon and SONGS are aging, and large numbers of employees will soon retire. It is critical to the ongoing reliability and safety of the plants that programs to transfer knowledge from retiring workers to new workers are successful and that strong safety cultures are maintained throughout this shift in the plants' workforces.

- Simulations find that no electricity supply shortages would occur as the result of either Diablo Canyon or SONGS being unexpectedly shut down for an extended period in the near term, nor would remedial action, such as additional demand response, energy efficiency, or additional capacity, be needed for reliability purposes. Replacement power for either plant would be supplied mostly by combined-cycle natural gas-fired plants, which are more expensive to operate and which emit more carbon dioxide than nuclear plants.

- The simulations did not assess local reliability impacts of an extended outage at either of the nuclear plants or the availability of adequate generation resources after 2012. More complete studies and detailed modeling will be needed periodically to reassess the availability of replacement power at a system and local level as supply and demand conditions evolve and local transmission constraints change.

- A prolonged shutdown of Diablo Canyon would not pose reliability concerns. However, a prolonged plant shutdown at SONGS could result in serious grid reliability shortfalls unless transmission infrastructure improvements are completed. Replacement power for SONGS would be available.

Economic, Environmental, and Policy

- The accumulation of nuclear waste at Diablo Canyon and SONGS is a long-term concern in the absence of a federal repository for disposing of spent fuel. If delays continue and spent fuel from SONGS has not been transferred to a repository within 40 years and from Diablo Canyon within 50 years, the spent fuel stored in dry casks on-site may need to be repackaged or the current spent fuel storage containers may need to be bolstered. This waste ultimately must be transported off-site, and spent fuel could require additional repackaging before transport. The long-term storage, packaging, and transport of this waste add to the expense and the risk of nuclear power in California.

- PG&E is planning to build sufficient on-site dry cask storage so that Diablo Canyon can continue operating past the plant's current license period or the spent fuel pool can be decommissioned when the current license expires without additional storage being required. Based on SCE's current plans for dry cask storage, SCE will run out of spent fuel storage space at SONGS several months before the end of the plant's current operating license. At that time, the plant will not be able to continue operating, and the spent fuel pool will not be able to be decommissioned unless SCE builds additional onsite dry cask storage or secures offsite storage.

- Currently, there is no low-level waste disposal facility in the United States available for California low-level waste except for the least radioactive grade ("Class A") of waste. Other classes of low-level waste (Class B and C) therefore must remain at the nuclear plant sites until a new or existing facility agrees to accept this waste. This does not pose a significant problem at present because the volume of this waste is relatively small, and the waste can be safely stored on site. However, the plants cannot be fully decommissioned until the waste is removed from the plant sites. In addition, given the scarcity of disposal options for low-level waste, the cost to dispose of the waste during plant decommissioning could be higher than currently anticipated. Indeed, low-level waste disposal costs have risen significantly in recent years, and estimates of disposal costs that were established in the most recent regulatory proceeding on decommissioning costs in 2005 are outdated.

- The experiences of several communities in other parts of the United States suggest that a dry cask storage facility at a plant site should not prevent the full decommissioning of the remainder of the plant site and the conversion of most of the site to alternative, productive uses. More study is required to assess the impact of a dry cask storage facility on local property values, business, and tourism, as current academic research into this issue is very limited.

- From a pure resource potential perspective, given adequate time California could license and build new renewable generation to replace the energy from Diablo Canyon and SONGS. However, since there are no large-scale renewable units with the same characteristics as baseload nuclear plants, current renewable technologies would require support of some natural gas-fired units to replace all the attributes of the nuclear plants. In addition, sufficient planning, siting, and construction time would be needed to develop these resources and any necessary transmission infrastructure. Based on current prices and technologies, replacing power from Diablo Canyon and SONGS primarily with renewable power would increase the overall cost of power to consumers. It would also replace certain environmental impacts, such as the adverse impacts from once-through cooling and nuclear waste generation, with other adverse impacts, such as avian mortality from wind towers, habitat fragmentation and risks of soil and water contamination from solar thermal plants, and greenhouse gas emissions from backup natural gas-fired plants. A more detailed study of power generation options is needed to quantify the reliability, economic, and environmental impacts of replacement power options.

- One of the challenges in replacing the nuclear plants with renewable power generating facilities would be the different impacts of this decision on different communities. If the new plants were built in California, the total economic benefit from employment and taxes statewide would be comparable to the benefits currently provided by the nuclear plants. Many of these benefits would likely be transferred from the coastal communities near Diablo Canyon and SONGS to communities in inland Southern California and throughout the state. Recent announcements of several planned large-scale solar facilities in San Luis Obispo County suggest that renewable power development could benefit San Luis Obispo County, thereby limiting the transfer of benefits away from the county.

- The economic impacts of closing Diablo Canyon could be offset by economic gains from alternate uses of the plant site, other commercial or industrial development elsewhere in the county, or a potential increase in property values as a result of the plant closure. Without such offsets, the loss of the plant would have a significant impact on the county's economy. The loss to the San Diego and Orange County economies from a closure of SONGS would be much less significant since these economies are more diversified and less dependent on the nuclear plant.

- A key uncertainty in assessing the economic benefits to keeping Diablo Canyon and SONGS operating through a 20-year license extension is the reliability of the plants as they age. If the plants continue to operate reliably and do not require additional large capital improvements, the cost of power from the nuclear plants will likely remain lower than the cost of power from new renewable resources. However, significant equipment failures could result in extended outages and expensive repairs. As discussed earlier, effective plant maintenance and a strong safety culture are critical to keeping the plants operating safely and reliably as they age.

CHAPTER 5: Evaluation of the Self-Generation Incentive Program

Introduction

Assembly Bill 2778 (Lieber , Statutes of 2006, Chapter 617) requires the Energy Commission, in consultation with the California Public Utilities Commission (CPUC) and the California Air Resources Board (ARB), to evaluate the CPUC's Self-Generation Incentive Program and the costs and benefits of expanding eligibility for the program to renewable and fossil fuel "ultraclean and low-emission distributed generation."

This chapter summarizes the preliminary results of a draft analysis by TIAX LLC under contract to the Energy Commission.[107] These results were presented at an Integrated Energy Policy Report (IEPR) staff workshop on September 3, 2008. The Energy Commission anticipates publishing the final TIAX report in October and will include the final results of that analysis in the final *2008 IEPR Update.*

Assembly Bill 970 (Ducheny, Chapter 329, Statutes of 2000) directed the CPUC to adopt initiatives to reduce electricity demand, including incentives for distributed generation technologies. The CPUC created the Self-Generation Incentive Program to promote eligible distributed generation technologies under 5 megawatts (MW) to meet all or a portion of customers' electricity needs.[108] The Self-Generation Incentive Program is one of the largest distributed generation incentive programs in the United States, with approximately 1,200 projects totaling 300 MW on-line by the end of 2007. The total capacity is fairly evenly divided between cogeneration and solar photovoltaic projects.[109]

From 2001 through 2004, funding for the Self-Generation Incentive Program was set at $125 million per year, which was collected through a surcharge on electricity and natural gas bills.[110] Rebates from the Self-Generation Incentive Program are available to electric and/or gas customers of Pacific Gas and Electric (PG&E), Southern California Edison (SCE), Southern California Gas Company, and San Diego Gas & Electric (SDG&E).

The Self-Generation Incentive Program was subsequently extended through December 31, 2007, by Assembly Bill 1685 (Leno, Chapter 894, Statutes of 2003). AB 2778 then extended the Self-Generation Incentive Program to January 1, 2012, and removed solar technologies from the

---

107 TIAX, LLC, *Cost Benefit Analysis of the Self Generation Incentive Program*, draft consultant report, September 2008, http://www.energy.ca.gov/2008_energypolicy/documents/index.html.

108 For more information on the early implementation of the Self-Generation Incentive Program, see CPUC Decision D.01-03-073.

109 http://www.cpuc.ca.gov/PUC/energy/sgip/051005_sgip.htm

110 CPUC, Decision 01-03-073, http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/6083.PDF, p. 7, 11-13, and 49-50.

program. Since January 1, 2007, the CPUC has offered incentives for photovoltaic technologies through the *California Solar Initiative.*[111] As of January 1, 2008, only fuel cells and wind energy technologies are eligible for the program.

Prior assessments of the Self-Generation Incentive Program by Itron, Inc., found that Self-Generation Incentive Program projects supply critical on-site electricity during peak demand, may reduce transmission and distribution system line loading and losses, reduced greenhouse gas (GHG) emissions in most instances compared to central station generation, and provide the most benefit to end-users and, in some instances, some benefit to the utilities.[112]

Analysis Approach and Method

Table 5 shows the benefits and costs included in TIAX's analysis of the Self-Generation Incentive Program. TIAX used a broader scope than what is usually used to evaluate cost-effectiveness of demand-side management programs in California.[113] Where possible, TIAX also quantified the costs and benefits to the participant and non-participant (for example, the ratepayer). The overall focus of the report was to develop a clear method to evaluate self-generation and distributed generation programs. A thorough cost-benefit analysis will yield results that are easily adapted to estimate more commonly used measures of cost-effectiveness.

Data Sources

In its cost-benefit analysis, TIAX used data on Self-Generation Incentive Program activity from 2002 through 2006. Data from 2007 was not included because of the time constraints imposed by the November 1, 2008, due date for the analysis. In May 2008, the CPUC formally requested the data needed for the TIAX analysis, including confidential customer data, from the investor-owned utilities (IOUs). These data included:

- **Metered Performance Data:** Itron collected metered performance data for distributed generation systems supported by the Self-Generation Incentive Program from 2002 through 2006. The metered data include electric net generator output, fuel consumption, and useful recovered thermal energy (heat).
- **Cost Breakdown Worksheets:** Self-Generation Incentive Program applicants are required to submit a Cost Breakdown Worksheet, which details eligible and ineligible cost elements for the installation. The eligible costs are used to determine the value of the incentive,

111 For more information regarding the California Solar Initiative, see CPUC Decision 06-01-024. Incentives for the use of solar in new home construction is available through the California Energy Commission's New Solar Homes Partnership. Publicly owned utilities also offer solar incentive programs. See http://www.gosolarcalifornia.org/csi/index.html.

112 CPUC Self-Generation Incentive Program, *Sixth Year Impact Evaluation Final Report*, August 30, 2007. Section 5.3 Transmission and Distribution Impacts.

113 For more information, see the *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects*, Governor's Office of Planning and Research, July 2002, provides guidance in the evaluation for the cost-effectiveness of demand-side management programs using tests from varying perspectives including participants, non-participants and total resource cost tests.

depending on the technology. Cost elements on the worksheets included engineering and design costs, permitting costs, equipment costs, interconnection fees, sales tax, and others.

Table 5. Benefits and Costs Considered in Evaluation

	Benefits	Costs
Participant	Customer environmental credits Customer reliability benefits Electric bill savings Fuel-for-heat savings Tax credits	Capital costs Fuel costs – operational Operation and maintenance expenditures Standby charges
Non-Participant	Avoided energy costs • Energy commodity savings • Congestion charge savings • Transmission losses savings Avoided ancillary service charges Avoided California ISO charges Congestion reduction savings Customer standby fees Distribution capital deferral savings Distribution loss savings Local reliability benefits	Administrative costs Lost revenues
Society	Avoided ancillary service charges Avoided California ISO charges Avoided energy costs Congestion reduction savings Customer reliability benefits Distribution capital deferral savings Distribution loss savings Economic impacts Fuel-for-heat savings Gas price moderation savings Indirect economic benefits Societal environmental benefits	Administrative costs Fuel costs – operational Operation and maintenance expenditures

Source: TIAX, LLC.

- **Utility Tariff Data:** The CPUC provided electricity tariff data, including time-of-use rates, non-bypassable charges, and standby rates. Forecasts of retail prices for both gas and electricity rely on current tariffs as a starting point. Retail electricity prices were escalated based on revenue requirement forecasts developed by the utilities. Retail gas rates were used to value both purchased generator input fuel and avoided purchases of natural gas resulting from recovered waste heat.

- **Transmission and Distribution System Data:** Substation size and physical locations, along with maximum line loads, transformer loads, and other system information.
- **Program Administration and Evaluation:** The CPUC provided annual administration costs for the Self-Generation Incentive Program and the costs incurred by the administrators for evaluations conducted by third-party consultants.

Estimating Macroeconomic Impacts

Jack Faucett Associates, a subcontractor with TIAX, estimated the macroeconomic impacts of the Self-Generation Incentive Program using an input-output model, IMPLAN. [114] To run IMPLAN, specific expenditures are allocated to a wide range of economic industries (509 total) to develop detailed estimates of economic impacts. The economic impacts of the program's expenditures included: value added, jobs created (full time equivalents), payroll compensation, federal tax revenue, and state and local tax revenue.

Estimating Environmental Impacts

TIAX characterized environmental benefits by comparing the emissions of the self-generation installations to the emissions that would have otherwise come from centralized power generation. TIAX determined the emissions from centralized power generation on a marginal basis, assuming that the next installed watt of power would come from a natural gas-fired combined-cycle combustion turbine power plant. It is important to note that although self-generation installations often operate at peak demand (for instance, solar photovoltaic (PV) systems) and may displace emissions from dirtier generation sources (for example, peaker plants), TIAX made a simplifying assumption and presented the environmental benefits as a conservative estimate.

TIAX quantified emissions that impact air quality – volatile organic compounds (VOC), nitrogen oxides (NO_x), particular matter (PM2.5), and carbon monoxide (CO) – and those that impact climate change – carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O), reported as carbon dioxide equivalents (CO_2-eq). Because air quality is driven primarily by local and regional chemistry and transport, TIAX used emission factors that accounted for all in-state emissions of air quality pollutants.[115] With climate change being a global phenomenon, TIAX employed life cycle emission factors that account for all upstream emissions of a fuel.[116]

---

114 Impact Analysis for PLANning (IMPLAN). For more information regarding this model, see http://www.economics.nrcs.usda.gov/technical/implan/implanmodel.html and http://www.implan.com/.

115 Note that the in-state emission factors account for pollutant offsets that are required for both NOx and PM.

116 This approach was used by TIAX in a previous report prepared for the California Energy Commission: *Full Fuel Cycle Assessment, Well to Tank Energy Inputs, Emissions, and Water Impacts*, Consultant Report, TIAX LLC, CEC-600-2007-003, June 2007. Note that electricity is considered an alternative transportation fuel.

TIAX used the damage cost of pollutants rather than the control cost to monetize emission reductions or increases.[117] The damage cost is typically measured on a per-ton basis and is a more accurate representation of the cost of a given pollutant to society. A control cost, on the other hand, reflects the cost of preventing that same pollutant from being emitted. The damage cost analysis included direct damages to humans as well as indirect damages to humans through ecosystem degradation and through non-living systems.

Table 6. Emission Factors for Centralized Power Generation Used in California and Corresponding Damage Costs (all values in $2006)

	Pollutant	**Emission Factors[a] (g/MWh)**	**$/ton**
Air quality	VOC	1.0	8.7 x 10^3 [b,c]
	NO_x	4.5	4.1 x 10^3 (gas phase)[b,c]
			19.5 x 10^3 (as PM)[c]
	CO	63	--
	PM2.5	6.2	640 x 10^3 [c]
Climate Change	GHGs	550 x 10^3	12[d]

[a] *Full Fuel Cycle Assessment, Well to Tank Energy Inputs, Emissions, and Water Impacts*, Consultant Report, TIAX LLC, CEC-600-2007-003, June 2007

[b] Delucchi, M. *Annualized Social Cost of Motor Vehicle Use in the U.S., 1990-1991*. Institute for Transportation Studies, University of California, Davis (UCD-ITS-RR-96-3)

[c] *Emission Reduction Plan for Ports and Good Movement, Appendix A: Quantification of the Health Impacts and Economic Valuation of Air Pollution from Ports and Goods Movement in California*, California Air Resources Board, March 2006

[d] Tol, RSJ. *The Marginal Damage Costs of Carbon Dioxide Emissions: An Assessment of the Uncertainties*. Energy Policy, 33 (2005), 2064-2074 [per metric ton]

Source: TIAX

TIAX used an estimate of the social cost of carbon dioxide as a proxy for damages related to GHG emissions. The Inter-Governmental Panel on Climate Change (IPCC) estimates this cost to be $43 per metric ton of carbon, which is equivalent to about $12 per metric ton of CO_2 (in 2006 dollars). The IPCC approximation is based on R.S.J. Tol's 2005 study,[118] which reviewed 28 published studies containing 103 estimates. Tol's work concluded that when only peer-reviewed studies are considered, "… climate change impacts may be very uncertain but it is unlikely that the marginal damage costs of carbon dioxide emissions exceed $50 per ton

117 For further discussion of damage costs, see: U.S. EPA, Office of Air Quality Planning and Standards, Economic Analysis Resource Document, April 1999, http://www.epa.gov/ttnecas1/econdata/6807-305.pdf.
118 Tol, RSJ. *The Marginal Damage Costs of Carbon Dioxide Emissions: An Assessment of the Uncertainties*. Energy Policy, 33 (2005), 2064-2074.

carbon." However, this estimate may be too low to stimulate the magnitude of GHG emissions reduction needed to avoid serious climate-related impacts.

The IPCC reports a 445–490 parts per million CO_2-eq as substantially reducing the expected magnitude, impact, and rate of climate change from business-as-usual scenarios by 2050 from 2000 emission levels and states that most individual studies for this category of reductions cluster around $100 per ton CO_2 by 2030.[119]

Transmission and Distribution System Impacts

RUMLA, Inc. (Rumla), a TIAX subcontractor, assessed the transmission and distribution grid impacts of the Self-Generation Incentive Program. Rumla used General Electric's Multi Area Production Simulation Software program to analyze transmission congestion, marginal losses, and the grid locational value of the throughput of the Self-Generation Incentive Program installations. The model calculated hourly production costs while accounting for the system security constraints imposed by the transmission system on the economic dispatch of generation.

RUMLA included the following factors in its analysis of transmission system impacts:

- Zone-specific wholesale market transactions for assessing the value of Self-Generation Incentive Program generation for Zones NP15 and SP15 over 2002-2008.
- California ISO's Market Redesign and Technology Update (MRTU) as the pricing platform from 2009 onwards.
- Anticipated transmission upgrades.
- Anticipated generation additions in compliance with the CPUC's Resource Adequacy Requirements.

Together, the MRTU and the resource adequacy developments should, on average, determine more than 95 percent of the total value of the avoided costs for Self-Generation Incentive Program-supported systems.

For the distribution impacts, Rumla assessed the need for distribution system upgrades in the absence of Self-Generation Incentive Program installation on a case-by-case basis using utilities' circuit data. Early results indicate there are indeed cases where the absence of the Self-Generation Incentive Program installation(s) would trigger feeder and/or transformer upgrades. When completed, the assessment will point out the extent to which the Self-Generation Incentive Program had produced distribution investments deferral savings for the ratepayers of each IOU.

---

119 California Energy Commission, *2007 Integrated Energy Policy Report*, p. 67, Footnote 66, based on Intergovernmental Panel on Climate Change, 2007, *Climate Change 2007: Mitigation. Contribution of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change*. Metz, B., O. R. Davidson, P. R. Bosch, R. Dave, and L. A. Meyer (eds). Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. <www.ipcc.ch/pdf/assessment-report/ar4/wg3/ar4-wg3-chapter3.pdf>, p. 198, Table 3.5 and p. 206.

Preliminary Results

TIAX analyzed 1,062 installations, amounting to 263.1 MW of installed capacity, that were interconnected on or before December 31, 2006. To date, Self-Generation Incentive Program projects have delivered more than 610,000 MWh[120] to California's electric grid. Past Self-Generation Incentive Program-funded projects have reduced GHG emissions by displacing grid electricity, using waste heat through cogeneration, and generating electricity with biogas.

TIAX identified limited environmental benefits from air quality and climate change perspectives aside from the previously funded photovoltaic generation. Economically, Self-Generation Incentive Program-funded projects have resulted in greater economic activity within California, with $1.689 billion value added to the state. Other positive economic benefits include job creation and income benefits.

Limiting incentives to fuel cells and wind technologies has severely restricted the development and use of the Self-Generation Incentive Program. The TIAX analysis suggests that distributed generation technologies using renewable and non-renewable fuels should be reinstated, especially those technologies used in combined heat and power (CHP) projects. If the original objectives of the program still stand, which call for "incentives for distributed generation to be paid for enhancing reliability" and "differential incentives for renewable or super clean distributed generation resources," then even generation technologies that do not run on a renewable fuel may enhance reliability and add significant value to the program participant, the ratepayer, and society as a whole.

The *2007 IEPR* noted the value of CHP systems in reducing carbon emissions because of their efficient use of fossil fuel through the capture of waste heat for other uses (such as power plant cooling).[121] Fuel sources for CHP systems include natural gas, biomass, coal, biogas, or fuel oil, and CHP currently does not qualify for Self-Generation Incentive Program funding. The TIAX analysis compared the efficiency of Self-Generation Incentive Program-funded systems to the efficiency of other distributed generation systems, including CHP. The analysis found that distributed generation, including CHP, continues to show value for customers seeking solutions in a fluctuating energy climate.

The avoided cost analysis found benefits in having excess generating capacity available in certain locations during peak periods. Energy storage technologies can provide such capacity benefits and should therefore be eligible for the program.

---

120 Data from 2006

121 California Energy Commission, *An Assessment of California CHP Market and Policy Options for Increased Penetration*, 2005, CEC -500-2005-173

Recommendations

Eligible Technologies

- Eligibility for the Self-Generation Incentive Program should be based on the overall efficiency and performance of systems, regardless of fuel type.

Alternative and Renewable Fuels

- Currently, renewable fuels are eligible for the Self-Generation Incentive Program only if used with a fuel cell system. The CPUC should consider re-instituting formerly eligible engine and turbine technologies that operate on landfill gas, digester gas from dairy waste or wastewater treatment processes, or biodiesel. Biodiesel can be produced from vegetable oils (for example, soybean, palm, and canola oils, and used cooking oil often referred to as yellow grease), and waste animal fats. Biomass waste streams (such as lawn clippings), food (restaurant) waste, agricultural waste (for example, seeds, pits, and husks), forest residue, commercial food industry waste, construction debris, and municipal solid waste can also be used to produce biofuels through pyrolysis to produce fuel oils and gas; gasification to produce synthetic fuel gas (producer gas or syngas); or conversion of syngas to diesel through Fischer-Tropsch synthesis.

Energy Storage

- The CPUC should consider providing self-generation incentives for energy storage. Energy storage technologies can provide capacity benefits and should therefore be eligible for the program. Energy storage can be coupled with generation or installed as stand-alone systems. The U.S. Department of Energy has funded studies showing the benefits of hybrid photovoltaic-battery storage and fuel cell-battery storage systems in certain locations.

Transmission and Distribution Benefits

- The CPUC should require that the IOUs meet a portion of their distribution system upgrades by procuring distributed generation or CHP in areas that provide locational benefits to the distribution system. The CPUC and Energy Commission should work collaboratively with the IOUs to identify locational benefits.

- A 2007 study by the DOE and its forthcoming study with SCE and Navigant Consulting (expected in October 2008) find that distributed generation can have location-specific grid benefits when sized correctly. The transmission and distribution costs avoided by such systems can be quantified with highly accurate customer and utility data. The Energy Commission should work with the CPUC to define additional studies to assess the performance of distributed generation in circuit areas providing locational benefits.

Combined Heat and Power Systems

- Previous IEPRs have recognized the value of distributed generation, particularly CHP, by encouraging policies that support market penetration in California. The CPUC has adopted some policies that permit the use of distributed generation, but economic barriers and the lack of incentives continue to hamper its development. To address these concerns, the CPUC should:

- Develop tariff structures that make distributed generation and CHP projects "cost and revenue neutral" while granting credit to owners for providing system benefits, such as reduced congestion.
- Eliminate all non-bypassable charges for distributed generation and CHP regardless of interconnection voltage and standby reservation charges.
- Work collaboratively with the Energy Commission to develop a method that estimates the value of Self-Generation Incentive Program-funded projects, as well as distributed generation costs and benefits.

Revise Self-Generation Incentive Program Incentive Structure to Better Support State Policy and Energy Goals

- The Self-Generation Incentive Program should evolve to better support state policy and energy goals for distributed generation technologies. Since the program's creation in 2001, the state has enacted new legislation that increases incentives for distributed generation development in California. These bills include Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006), which sets GHG emission reduction goals, and Assembly Bill 1613 (Blakeslee, Chapter 713, Statutes of 2007), which requires electrical corporations to purchase excess electricity generated by CHP and provides a pay-as-you-save pilot program to finance the upfront costs of CHP for nonprofit entities. AB 1613 also requires the Energy Commission to develop CHP regulations for system size, efficiency standards, cost-effectiveness, technical feasibility, and environmental benefits by January 1, 2010. Finally, Senate Bill 1 (Murray, Chapter 132, Statutes of 2006) implemented incentive programs for consumers to install solar distributed generation systems. Therefore, the CPUC should develop an incentive structure for Self-Generation Incentive Program projects that meet specific targets for environmental, transmission and distribution, and economic benefits.

CHAPTER 6: State Progress on Key Integrated Energy Policy Report Recommendations

The *Integrated Energy Policy Report (IEPR)* is a real-time, public forum for continuing dialog about California's energy policies. This chapter examines the progress the state has made in addressing key recommendations made in past *IEPRs* (shown in italics) on electricity and procurement issues, energy efficiency requirements, demand response, load management standards, renewable energy issues and goals, distribution system and combined heat and power, nuclear power, transmission, natural gas, transportation, petroleum infrastructure, land use, and water/energy.

Electricity and Procurement

Statewide Progress on Electricity/Procurement Issues	Substantial	On Track	Improvement Needed
More public scrutiny on utility resource solicitations, discontinue use of procurement review groups			✓
Focus on portfolio analysis of future resource fuel types		✓	
Develop common portfolio analytic methodology to influence IOU long-term procurement plans	✓		

Beginning with the 2006 procurement proceeding, the California Public Utilities Commission (CPUC) should allow more public scrutiny and debate on utility resource solicitations, the application of least-cost, best-fit criteria for selecting resources, and utility choices for meeting long-term resource needs. In addition, the CPUC should discontinue its use of procurement review groups (2005 IEPR).

The CPUC has only partially implemented these recommendations. In response to the *2005 IEPR* and concerns previously expressed by the Legislature in Senate Bill 1488 (Bowen, Chapter 690, Statutes of 2004), the CPUC opened a proceeding in 2006[122] to discuss issues related to confidentiality and utility procurement. In June 2006, the CPUC required the utilities to provide the public with detailed descriptions of utility least-cost, best-fit criteria used to select resources in the planning and procurement process.[123] However, the CPUC continued to hold a substantial amount of procurement-related materials confidential.

Since 2006, the CPUC has increased access to procurement-related information. Most notably, in D.07-12-052, the CPUC required discussions on resources procured by the investor-owned utilities (IOUs) to meet system needs (as opposed to bundled customer needs) to be open to electric service providers, who will be liable for a share of the costs. The decision also required

122 R.05-06-040.

123 D.06-06-066.

greater transparency in Independent Evaluator[124] assessments and public notices about procurement review group (PRG) meetings and agendas.

The CPUC has decided to continue using the PRGs. The CPUC testified at an IEPR workshop on July 14, 2008, that it, the IOUs, and ratepayer advocates believe the PRGs are a necessary tool in allowing discovery in a timely fashion while preserving the confidentiality of market-sensitive information.

The Energy Commission should ensure that portfolio analysis of future resource fuel types is a primary focus of the next Energy Report cycle (2005 IEPR).

The state has made some progress on this recommendation. As part of the *2007 IEPR*, Energy Commission staff investigated state-of-the-art utility portfolio-based planning and analysis. Staff examined how utilities in the western United States incorporate uncertainties like fuel price and carbon risk into their planning processes, described the current planning processes of the California IOUs, and evaluated several portfolio-based planning processes.

The Energy Commission published its findings in *Portfolio Analysis and its Potential Application to Utility Long-Term Planning*, which provided background material for workshops in June and July 2007. Based on the information presented, the *2007 IEPR* recommended developing a common portfolio method to influence the long-term procurement plans filed by the IOUs. As noted below, the CPUC's 2008 Long-Term Procurement Proceeding[125] is focusing on the information needed from the IOUs to facilitate portfolio-based analysis as well as the analysis itself.

A common portfolio analytic methodology [be developed] to clearly influence the long-term procurement plans filed by the investor-owned utilities (2007 IEPR).

The state has made substantial progress on this recommendation. The Energy Commission staff has been collaborating with the CPUC in Phase I of the 2008 Long-Term Procurement Proceeding. This phase is developing a set of standard input assumptions and sensitivities, scenarios, and reporting formats and metrics for the 10-year plans that the IOUs submit to the CPUC every two years. The goal is to evaluate a number of potential resource plans under many and varied futures, including different assumptions about electricity demand, fuel prices, carbon costs, and so on, to adequately incorporate risk into the portfolio selection process.

Increased attention to the shortcomings of the 2006 procurement plans, in combination with recent volatility of major cost drivers and reactions to that volatility, has contributed to the emphasis on assessing risk in evaluating the 2010 procurement plans. Many decisions remain about sensitivities and scenarios to be modeled in the development of the 2010 plans, but the IEPR Committee believes that the sensitivity values and scenarios selected for analysis will be

124 The California Public Utilities Commission requires an Independent Evaluator for each Renewable Portfolio Standard solicitation to provide third party oversight and a critical assessment of the procurement process.
125 R.08-02-007

diverse enough to allow regulators and stakeholders to assess the cost and risk tradeoffs in the IOUs' resource planning.

Energy Efficiency

Statewide Progress on Energy Efficiency Requirements	Substantial	On Track	Improvement Needed
Establish reporting requirements for publicly owned utilities	✓		
Adopt statewide efficiency targets for 2016 equal to 100 percent of economic potential	✓		

The Energy Commission should establish, consistent with SB 1037, reporting requirements for publicly owned utilities to ensure that their energy efficiency goals are comparable to those required of investor-owned utilities (2005 IEPR).

The state has made substantial progress on this recommendation. Senate Bill 1037 (Kehoe, Chapter 366, Statutes of 2005) required the publicly owned utilities, for the first time, to describe their energy efficiency programs, expenditures, and expected and actual energy savings results to their customers and the Energy Commission each year. Publicly owned utilities voluntarily provided the first of these annual reports in December 2006. The Energy Commission updated its data collection regulations in 2006 and established March 15 as the submittal date for the annual reports. The publicly owned utilities use methods similar to those used by the investor-owned utilities to report energy efficiency expenditures and savings. A CPUC consultant developed a standardized quantification method, the *Energy Efficiency Reporting Tool*, to estimate energy and peak reductions from efficiency programs.

Also in 2006, Assembly Bill 2021 (Levine, Chapter 734, Statutes of 2006) required publicly owned utilities to develop efficiency potential and targets in cooperation with the Energy Commission, which were adopted by the Energy Commission in December 2007. Staff is using the annual savings targets to keep track of energy efficiency progress of the publicly owned utilities and of all utilities toward meeting statewide goals set by the Energy Commission and CPUC under AB 2021. In March 2008, the California Municipal Utilities Association provided the Energy Commission with its first progress report since the energy efficiency targets were adopted in December 2007. Public utility spending on energy efficiency averages around 1 percent of revenue.

Adopt statewide energy efficiency targets for 2016 equal to 100 percent of economic potential, to be achieved by a combination of utility programs, state and local standards, and other programs (2007 IEPR).

The state has made substantial progress on this recommendation. AB 2021 required the Energy Commission and the CPUC to develop statewide estimates of all cost-effective energy efficiency and demand reduction potential and savings targets for utilities (both publicly and investor-owned) for a 10-year period.

During 2007, the Energy Commission and the CPUC, together with the utilities, collaborated to fulfill the mandates of AB 2021. In the resulting report,[126] the Energy Commission analyzed data on energy efficiency potential submitted by the publicly owned utilities and by the CPUC for the investor-owned utilities. The Energy Commission adopted statewide goals equivalent to all cost-effective efficiency potential in December 2007. While these goals are higher than those proposed by the utilities, they were set with the understanding that California's utilities will cooperate in the future with private and public entities to maximize savings and fulfill 100 percent of the economic potential.

Demand Response

Statewide Progress on Demand Response Recommendations	Substantial	On Track	Improvement Needed
Pursue actions to ensure demand response goals are met			✓
Develop and implement dynamic rates for customers with advanced metering		✓	
Develop better understanding of publicly owned demand response efforts and goals similar to those of investor-owned utilities		✓	
Initiate formal rulemaking process for adoption of load management standards		✓	

The CPUC and the Energy Commission must vigorously pursue actions to ensure that the state's demand response goals are met (2005 IEPR).

The state has made little progress on this recommendation. The *2005 IEPR* called for a 5 percent peak reduction from price-responsive demand response in the IOU service territories by 2007. This goal was not met partly because the CPUC refused to approve an all-party settlement that would not have adopted default opt-out critical peak pricing (CPP) rates for large customers. Commercial and industrial customers and trade groups argued against the default rates because of potential business cost increases. In the settlement, the parties proposed opt-in instead of opt-out CPP rates, which did not represent a significant change from existing rates. The CPUC decided to reintroduce default CPP rates in the next general rate case cycle rather than adopt the settlement agreement. Another barrier to meeting the 5 percent goal was the need for interval or advanced meters for customers with loads below 200 kilowatts. The most recent timetable for the roll out of advanced meters shows installation being completed by 2012 for all three IOUs.

The CPUC has set timetables to introduce default CPP rates for large commercial and industrial customers with loads 20 kilowatts and above. In addition to these dynamic pricing programs, IOUs have also increased enrollments in incentive-based demand response programs. The upper estimate of enrolled MWs increased from 850 MWs in July 2005 to 1,136 MWs in April

126 California Energy Commission, *Statewide Energy Efficiency Potential Estimates and Targets for California Utilities*, August 2007, http://www.energy.ca.gov/2007publications/CEC-200-2007-019/CEC-200-2007-019-SD.PDF.

2008, approximately 2.3 percent of system peak in 2007. However, this increase in non-emergency demand response still falls well short of the 5 percent goal.

The CPUC needs to develop and implement dynamic rates for all customers with advanced metering (2005 IEPR).

The state has made substantial progress on this recommendation. In May 2008, SDG&E implemented default CPP rates for customers with loads of 20 kW and above. These rates offer an opt-out provision as well as an option to pay a capacity reservation charge to avoid high prices on a specified amount of load. In July 2008, the CPUC set a timetable for PG&E to develop a new "dynamic pricing" rate structure. This dynamic pricing decision can also be applied to the next general rate cases of SDG&E and SCE. SDG&E has also implemented a peak-time rebate tariff for commercial and residential customers, which provides a minimum credit of $0.75/kWh for each kWh of reduced consumption during a rebate event period. PG&E and SCE are also proposing peak-time rebate tariffs.

By the end of 2006, the Energy Commission should work closely with publicly owned utilities to better understand their demand response efforts, and develop goals similar to those required of investor-owned utilities (2005 IEPR).

The state has made progress on this recommendation. The Energy Commission did not begin this process before the end of 2006 as planned; however, in 2007 the Energy Commission held two workshops on demand response and the agency's load management authority, where publicly owned utilities and IOUs provided a status of their demand response efforts in California. These workshops, along with other conferences, meetings, and working groups held in 2006 and 2007, provided a venue for increased dialog, resulting in a better understanding of publicly owned utility demand response activities. Additional dialogue with the POUs has occurred in 2008 through the Load Management Standards Proceeding.

Initiate a formal rulemaking process involving the CPUC and California ISO in 2008 to pursue the adoption of load management standards under the Energy Commission's existing authority (2007 IEPR).

The state is on track with this recommendation. In January 2008, the Energy Commission approved an Order Instituting Informational and Rulemaking Proceeding on demand response equipment, rates, and protocols. The Energy Commission's Efficiency Committee hosted six workshops in Sacramento between March and July 2008 at which the CPUC, California ISO, all major utilities, and numerous other stakeholders participated.

Energy Commission staff is preparing a series of load management standards recommendations for public review and will prepare a proposed package of load management standards before the end of 2008 for initial review by the Office of Administrative Law, with adoption of the standards anticipated by spring of 2009.

Renewable Energy

Statewide Progress on Renewable Energy Recommendations	Substantial	On Track	Improvement Needed
Apply same RPS targets, timelines, and eligibility to publicly owned utilities as for investor-owned utilities			✓
Allow limited use of renewable energy certificates for RPS compliance			✓
Maintain penalties for RPS non-compliance and eliminate penalty cap			✓
Implement feed-in tariff for RPS-eligible renewable up to 20 MW			✓
Begin collaborative process to develop feed-in tariffs for larger projects		✓	
Establish feed-in tariff for excess generation from customer-owned solar installations		✓	

The Legislature should apply the same RPS targets, timelines, and eligibility standards to publicly owned utilities that it has established for IOUs. Consistent with the Energy Commission's 2004 recommendation, the state should establish an exemption process for small publicly owned utilities to avoid the overly burdensome requirements that compliance with RPS goals may present (2005 IEPR).

The state has made slow progress on this recommendation. Currently, the RPS standards for IOUs do not apply to publicly owned utilities, but do require them to implement standards that encourage renewable resources. Some publicly owned utilities have recently adopted RPS targets or timeframes at least as aggressive as those for the retail sellers. For example, Los Angeles Department of Water and Power, Riverside, Palo Alto, and Azusa have advanced their 20 percent renewable energy targets to 2010 or sooner.

Senate Bill 107 (Simitian and Perata, Chapter 464, Statutes of 2006) requires publicly owned utilities to annually report their status in implementing an RPS program and their progress toward attaining their RPS targets to their customers and to the Energy Commission.[127] The law does not provide an exemption process for smaller publicly owned utilities in complying with their RPS requirements.

The Energy Commission anticipates publishing a consultant report *The Progress of California's Publicly Owned Utilities in Meeting the State's Renewables Portfolio Standard* in fall 2008 based on data from the publicly owned utilities for 2003 through 2006. The report compares their RPS targets, renewable deliveries, and renewables procurement efforts to those of the state's three major IOUs.

The Legislature should authorize the CPUC to allow limited use of renewable energy certificates for RPS compliance to facilitate uniform participation of all load serving entities,

127 Public Utilities Code Section 387(b).

with the associated electricity sold into the California ISO real time market or bilaterally to retail sellers (2005 IEPR).

The state is making slow progress on this recommendation. Currently renewable energy credits (RECs) and the associated electricity generation must be procured as a bundled product to satisfy California's annual RPS targets. In 2006, SB 107 conditionally authorized the CPUC to allow unbundled RECs to satisfy RPS requirements[128] once the CPUC and Energy Commission confirm that the RPS tracking system meets SB 107 requirements. SB 107 also allows the CPUC to limit the amount of unbundled (or tradable) RECs procured by a retail seller to meet its RPS requirements.

In September 2007, the CPUC released a straw proposal of compliance rules for tradable RECs. The CPUC followed with a pre-hearing conference in December 2007. In July 2008, the CPUC issued a draft Proposed Decision on the definition and attributes of a REC. In addition, the Energy Commission and the CPUC developed the *Joint Commission Staff Report on Tracking System Operational Determination*. The Energy Commission released the first draft and held a staff workshop in March 2008. The CPUC plans to release a revised draft in September 2008, with both commissions planning to adopt the final report shortly thereafter.

It is anticipated that once the CPUC adopts a final REC definition and both agencies adopt the *Joint Agency Staff Report*, the CPUC will continue its proceeding to consider authorizing retail sellers to use unbundled RECs for RPS compliance.

The state should maintain the per-kilowatt-hour penalties for investor-owned utility non-compliance with Renewables Portfolio Standard goals consistent with California Public Utilities Decision 06-05-039, and eliminate the current per-utility cap on those penalties (2006 IEPR Update).

The state has maintained the authority to apply penalties of 5 cents per kilowatt-hour for IOU non-compliance with RPS goals, but has not made progress in eliminating the $25 million per-utility penalty cap established in the CPUC Decision 03-06-071.

The state has expanded the use of flexible compliance rules that allow retail sellers to carry a deficit in meeting their RPS targets. SB 107 modified the flexible compliance rules to include insufficient transmission, and in February 2008, the CPUC conditionally accepted the 2008 RPS Procurement Plans by stating that a deficit may be excused for up to three years if it results from insufficient transmission.[129]

128 Section 399.16 of the Public Utilities Code.

129 CPUC Decision 08-02-008; the retail seller must demonstrate that it has undertaken all reasonable efforts to use flexible delivery points, ensure availability of any needed transmission capacity, construct needed facilities (for electric corporations), and demonstrate that there is no conflict with any requirement relative to the retail seller's overall procurement plan.

SB 107 also applied the flexible compliance rules to all years, rather than up to 2009, and CPUC Decision 08-02-008 effectively extends the date for applying penalties for non-compliance beyond 2010 to 2013.

The CPUC should immediately implement a feed-in tariff, set initially at the market price referent, for all RPS-eligible renewables up to 20 megawatts in size (2007 IEPR).

The state has made slow progress on this recommendation. In July 2007, the CPUC adopted what are essentially feed-in tariffs as well as standard contracts for up to 250 MW of RPS-eligible renewable energy from water, wastewater, and other customers sold to electrical corporations at the market price referent.[130] In Decision 07-07-027, the CPUC expanded this program to include SCE and PG&E customers other than water/wastewater and set a limit of 228.4 MW for this expansion, with feed-in tariffs available under this decision as of February 14, 2008.[131] On September 18, 2008, the CPUC issued Decision 08-09-033,[132] which expanded the program to include all SDG&E customers as well.

In addition, through 2008 or until 250 MW are contracted, SCE is offering standard contracts for biogas and biomass generators not larger than 20 MW. The contracts are priced at the 2006 market price referent. As of early June 2008, SCE had 11 MW under contract, 23 MW in negotiation, and 22 MW of inquiries. If 250 MW are not contracted by the end of 2008, SCE may consider offering the contracts in 2009.[133]

Also, "[e]lectrical corporations are required to have a tariff/standard contract for the purchase of electricity from certain customers up to 20 MW (Public Utilities Code Section 2840 et seq.; Assembly Bill 1613, effective January 1, 2008, requiring an electrical corporation to file a tariff/standard contract for the purchase of electricity delivered by a combined heat and power system up to 20 MW)."[134] Implementation of this requirement is being undertaken through CPUC Rulemaking 06-05-027. The CPUC established the scope and schedule for additional work in June 2008.

---

130 Decision 07-07-027.

131 CPUC Resolution E-4137, http://docs.cpuc.ca.gov/WORD_PDF/FINAL_RESOLUTION/78934.PDF.

132 California Public Utilities Commission, September 18, 2008, http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/91159.htm.

133 KEMA, Inc., 2008, *Exploring Feed-in Tariffs for California: Feed-In Tariff Design and Implementation Issues and Options*, Draft Consultant Report, prepared for the California Energy Commission, http://www.energy.ca.gov/2008publications/CEC-300-2008-003/CEC-300-2008-003-D.PDF, p. 3-4. For more information, see http://www.sce.com/NR/rdonlyres/F0F1759B-8D9B-4DD9-B249-6879680DD531/0/080314_BSC_Protocol.pdf.

134 CPUC, June 5, 2008, Amended Scoping Memo and Ruling of Assigned Commissioner Regarding Phase 2 of Tariff and Standard Contract Implementation for RPS Generators, in Rulemaking 06-05-027, p. A3, as cited by KEMA, Inc., 2008, Exploring Feed-in Tariffs for California, p. 5.

The Energy Commission should begin a collaborative process with the CPUC to develop feed-in tariffs for larger projects (2007 IEPR).

The state is making progress on this recommendation. The Energy Commission and the CPUC are working together to develop a report that addresses the issues and options regarding feed-in tariffs for projects greater than 20 MW. In June 2008, the Energy Commission held a staff workshop on its draft consultant report, *Exploring Feed-In Tariffs for California: Feed-In Tariff Design and Implementation Issues and Options.*[135] A staff second workshop is scheduled on October 1, 2008, followed by a committee workshop on November 20, 2008. The final report is anticipated by the end of 2008.

The Energy Commission and the CPUC should work together to establish an appropriate feed-in tariff for excess generation from customer-owned solar installations based upon the RPS market price referent and time-of-delivery adjustment (2007 IEPR).

The state is making progress on this recommendation. CPUC Decision 07-07-027 implemented feed-in tariffs for RPS-eligible renewable energy generated by customers up to 1.5 MW in size, including those using distributed generation solar installations. Participants may sell all their RPS-eligible renewable energy or just the excess energy not used on site. The price for customer generation of RPS-eligible renewable energy is set at the market price referent used for the RPS and includes a time-of-delivery adjustment.

Electric Distribution System/Combined Heat and Power

Statewide Progress on Electric Distribution System/ Combined Heat and Power Recommendations	Substantial	On Track	Improvement Needed
Self-Generation Incentive Program incentives should be based on overall efficiency and performance			✓
Continue work of Rule 21 collaborative working group on interconnection issues	✓		
Develop distributed generation portfolio standard		✓	
Adopt revenue neutral programs to enable high efficiency combined heat and power to export power to utilities			✓

The CPUC's self-generation program incentives should be based upon overall efficiency and performance of systems, regardless of fuel type (2007 IEPR).

The state has not implemented this recommendation. The Legislature introduced Senate Bill 1012 (Kehoe) and Assembly Bill 1064 (Lieber and Fuentes) that would have extended self-generation incentives based on overall efficiency and performance, regardless of fuel type, but neither bill passed during the 2007-2008 session.

135 KEMA, Inc., 2008, *Exploring Feed-in Tariffs for California: Feed-in Tariff Design and Implementation Issues and Options*, Draft Consultant Report, prepared for the California Energy Commission, http://www.energy.ca.gov/2008publications/CEC-300-2008-003/CEC-300-2008-003-D.PDF.

The CPUC should continue the work of the "Rule 21" industry/utility collaborative working group to refine interconnection standards, provide third party resolution of interconnection issues, and streamline permitting (2007 IEPR).

The state has made substantial progress on this recommendation by refining interconnection standards through the efforts of the Rule 21 Interconnection Working Group. In June 2008, the Energy Commission transferred leadership of the working group to the CPUC, which is working with stakeholders to get agreement on what additional issues (as identified by the Energy Commission) they should address. New issues may be referred to and discussed in existing and new distributed generation proceedings at the CPUC. The working group will carry on the collaborative process and mediation of interconnection issues as established by the Energy Commission. In the future, the Energy Commission will continue to provide support for additional research initiatives that the group identifies in the area of standards and smart grid.

The CPUC should develop a distributed generation portfolio standard, including combined heat and power regardless of size or interconnection voltage, for electric utility procurement plans. Alternatively, the utilities could be required to treat distributed generation and combined heat and power, regardless of size or interconnection voltage, like efficiency programs (2007 IEPR).

The state is making progress on this recommendation. The Legislature enacted Assembly Bill 1613 (Blakeslee, Chapter 713, Statutes of 2007), which requires utilities to include export power from new combined heat and power (CHP) projects of 20 MW and under in their long-term procurement plans. The CPUC must decide whether to limit the amount of exports the IOUs are required to purchase. However, the IEPR Committee believes the state should implement AB 1613 and evaluate results before these limits are set. CHP developers face significant cost risks that include natural gas price volatility and increasing costs associated with equipment purchases. The CPUC should develop mechanisms to address these critical risk factors.

To meet the requirements of AB 1613, the Energy Commission will institute a rulemaking and establish operational requirements for qualified CHP facilities. The Energy Commission will also participate in a CHP Order Instituting Rulemaking (OIR) to be initiated by the CPUC to help resolve critical issues that hinder development of clean and efficient CHP projects in California. During this proceeding, the participants will discuss the issue of CHP projects that are 20 MW or larger.

The CPUC should adopt revenue-neutral programs that would enable high-efficiency combined heat and power to more easily export power to interconnected utilities (2007 IEPR). These programs should not lead to additional non-bypassable charges and could include:

- ***Providing the option for utilities to procure natural gas for combined heat and power plants at customer sites on the same basis they do for central power plants.***

  The state has made slow progress on this part of the recommendation. Regarding fuel costs, CHP customers or developers must absorb natural gas price swings immediately. Therefore, the success of AB 1613 depends on linking the fuel component of the price paid for excess energy to the market price of natural gas to allow CHP customers or developers timely recovery of their fuel costs. This issue and possible solutions will be discussed in the AB 1613 proceeding and in a subsequent CHP OIR.

- ***Counting combined heat and power plant output toward energy efficiency goals for utilities.***

  The state has made slow progress on this part of the recommendation. AB 1613 and the CHP OIR will provide forums for discussing how to accomplish aligning the interests of CHP customer-generators, the utilities, and ratepayers similar to the way the state has aligned the interests of providers, utilities, and ratepayers in the area of energy efficiency. California's current energy efficiency programs should provide models and strategies that will support CHP development and goals.

- ***Providing a portfolio standard with steadily increasing requirements for combined heat and power plant generation.***

  The state has made slow progress on this part of the recommendation. AB 1613 directs the CPUC to require the IOUs to establish tariffs and to require that electrical corporations purchase excess electricity from CHP systems (20 MW and under) that meet the efficiency standards adopted by the Energy Commission. This is a good first step but does not establish a portfolio standard that will include both large and small CHP.

  The California Air Resources Board's (ARB) Climate Change Draft Scoping Plan estimates that CHP will substantially contribute to reducing greenhouse gas (GHG) emissions. Increasing the deployment of CHP to meet these goals will require coordination between the Energy Commission, CPUC, and ARB to assure that barriers to development of clean and efficient CHP facilities in California will be addressed. Options to encourage widespread development of CHP systems in the Scoping Plan include a CHP portfolio standard, as well as utility-provided incentive payments, transmission and distribution payments, and feed-in tariffs. The ARB has formed a new CHP working group to explore these and other options. As a member of this group, the Energy Commission will work with all parties to support this goal.

Nuclear Power

Statewide Progress on Nuclear Power Recommendations	Substantial	On Track	Improvement Needed
Evaluate long-term implications of continuing accumulation of spent nuclear fuel	✓		
Take an active role in Yucca Mountain licensing proceeding		✓	

The state should evaluate the long-term implications of the continuing accumulation of spent nuclear fuel at California's nuclear plants (2005 IEPR).

The state has made substantial progress on this recommendation. In 2007, the Energy Commission published the contractor report *Nuclear Power in California: 2007 Status Report*, which provided a status on nuclear storage issues. In addition, Assembly Bill 1632 (Blakeslee, Chapter 722, Statutes of 2006) requires the Energy Commission to assess the costs and impacts from nuclear waste accumulating at California's nuclear power plants. To meet these requirements, the Energy Commission hired a technical consultant to conduct this assessment, which was completed in September 2008. Following a public workshop on the draft report and consideration of public comments, the Energy Commission will prepare the *AB 1632 Committee Report* for adoption in November 2008.

To ensure that California's interests are protected, the state should take an active role in Yucca Mountain licensing proceeding and challenge the Department of Energy's inadequate response to potential impacts previously identified during the environmental impact statement and review process (2007 IEPR).

The state has made progress on this recommendation. The California Attorney General's Office and the Energy Commission have joined together in representing California in the U.S. Nuclear Regulatory Commission's (NRC) proceeding to review the Department of Energy's license application for the proposed Yucca Mountain repository in Nevada. The Energy Commission has established California's Web link whereby the state's documents are posted on the NRC's License Support Network.[136] The Energy Commission also co-chairs the Western Interstate Energy Board (WIEB) High-Level Radioactive Waste Committee and participates on the Western Governors' Association (WGA) Waste Isolation Pilot Plant Advisory Group to continue working with other states and federal agencies in preparing for federal nuclear waste shipments.

The Energy Commission also coordinates a California Nuclear Transport Working Group to prepare for federal nuclear waste shipments in California and participates on the Department of Energy's Transportation External Coordination Group, which coordinates federal, state, industry and Indian tribe preparation for federal nuclear waste shipments. The Energy Commission will continue to participate in the state regional group planning activities for nuclear waste shipments through the WIEB and WGA activities.

136 http://lsnnet.gov/.

Transmission

Statewide Progress on Transmission Recommendations	Substantial	On Track	Improvement Needed
Transfer transmission permitting responsibility to Energy Commission			✓
Develop comprehensive planning process	✓		
Establish statewide corridor planning process to designate corridors for future use	✓		
Work collaboratively with state, federal, local, and regional planning agencies, investor-owned utilities, publicly owned utilities, generators and developers, and the public	✓		
Participate in federal corridor planning efforts	✓		
Implement changes to California ISO tariff to encourage construction of transmission for renewables	✓		

To better align transmission with generation permitting and planning and ensure that needed transmission investments occur, the Energy Commission recommends that the Legislature transfer transmission permitting responsibility from the CPUC to the Energy Commission using the framework laid out in the Warren-Alquist Act for generation siting that has worked successfully for the last 30 years (2005 IEPR).

The state has not implemented this recommendation. Although the CPUC has issued directives to streamline the permitting process and facilitate more efficient review of transmission projects, these internal changes have failed to result in timely project decisions.

The *2007 Strategic Transmission Investment Plan* recommended 10 specific near-term transmission projects that improve system reliability, reduce congestion, and/or interconnect renewable resources.[137] The status of those projects under the permitting jurisdiction of the CPUC is as follows:

- Phase I of the Tehachapi Transmission Plan consists of three segments. Segment 1 (Antelope-Pardee 500 kV Transmission Project) received unanimous Certificate of Public Convenience and Necessity (CPCN) approval on March 1, 2007. The United States Forest

[137] The 10 projects are San Diego Gas & Electric's Sunrise Powerlink 500 kV Project; Southern California Edison's Tehachapi Renewable Transmission Plan (Segments 1 through 3 in the 2005 Strategic Plan plus the remaining segments in the 2007 Strategic Plan); the Imperial Valley Transmission Upgrade Project; Pacific Gas and Electric Company's Central California Clean Energy Transmission Project; the transmission component of the Lake Elsinore Advanced Pumped Storage Project; the Green Path Coordinated Projects; the Los Angeles Department of Water & Power Tehachapi Project; Southern California Edison's Palo Verde – Devers No. 2 500 kV Project; and the TransBay Cable Project.

Service issued a Record of Decision on August 21, 2007, selecting its preferred alternative route and authorizing a 50-year special use permit for the project across Forest Service lands. Segments 2 (Antelope-Vincent 500 kV) and 3 (Antelope-Tehachapi 500 kV and 220 kV) received unanimous CPCN approval on March 15, 2007.

- SCE applied for a CPCN for Tehachapi Segments 4-11 on June 30, 2007. SCE anticipates project approval in early 2009, various segments under construction by 2011, and all segments completed by the end of 2013.
- The CPCN for the Palo Verde – Devers No. 2 500 kV line has been approved by the CPUC but the Arizona Corporation Commission (ACC) has denied permits for the Arizona portion of the project. As a result, SCE has requested approval from the CPUC to begin construction of the California-only portions of the project. In addition, SCE is pursuing two approaches for approval of the Arizona portions of the project, including a new project filing with the ACC and initiation of the prefiling process with the Federal Energy Regulatory Commission.
- SDG&E initially applied for a CPCN for the Sunrise Powerlink Project on December 14, 2005 and submitted an amended application on August 4, 2006. The CPUC and Bureau of Land Management (BLM) issued a Draft Environmental Impact Report (EIR)/Environmental Impact Statement (EIS) on January 3, 2008. A recirculated Draft EIR/EIS was released on July 11, 2008. It is expected that the CPUC will issue a decision by the end of 2008.

The Energy Commission recommends that a comprehensive transmission planning process is developed that includes the California ISO, the CPUC, other key state and federal agencies, local and regional planning agencies, IOUs and publicly owned utilities, generation owners and developers, and other interest groups to achieve statewide policy objectives (2005 IEPR).

The state has made substantial progress on this recommendation. In late 2005, the Energy Commission began working with the CPUC and the California ISO to better coordinate transmission and generation planning and procurement. In 2006, the Energy Commission and California ISO collaboratively developed a single transmission planning process to coordinate the Energy Commission’s IEPR and Strategic Transmission Investment Plan proceedings with the California ISO’s new grid planning process. As a result, the Energy Commission provides the IEPR’s electricity load forecast and other planning assumptions to the California ISO for its analyses of transmission path upgrades and specific projects.

Lack of transmission has been identified as one of the primary barriers to achieving the state’s renewable energy policy goals. In September 2007, the Energy Commission collaborated with the CPUC, the California ISO, investor-owned utilities, and publicly owned utilities to initiate the California Renewable Energy Transmission Initiative (RETI), a statewide, open, and transparent collaborative planning process. RETI is designed to facilitate and coordinate the planning and permitting of transmission and generation projects needed to accommodate the state’s renewable policy goals, support future energy policy, facilitate transmission corridor designation, and minimize the duplication of efforts.

RETI involves a broad range of stakeholders who are assessing competitive renewable energy zones (CREZs) in California and neighboring states that can provide significant electricity to consumers by 2020 and be developed in the most cost-effective and environmentally benign manner. RETI will also prepare detailed transmission plans to reach CREZs identified for development and recommend the next transmission project or projects that should be developed to connect remote renewable energy resources to the grid.

The Legislature should give the Energy Commission the statutory authority to establish a statewide transmission corridor planning process and designate corridors for future use, enabling environmental reviews to begin earlier in the process and shortening the timeframe of the transmission infrastructure planning and permitting processes (2005 IEPR).

The state has made substantial progress on this recommendation. In 2006, Senate Bill 1059 (Escutia and Morrow, Chapter 638, Statutes of 2006) authorized the Energy Commission to lead both the transmission corridor planning and electricity transmission corridor zone designation processes, which are coordinated with local land use permitting activities. In early 2007, the Energy Commission initiated a rulemaking to establish regulations for the implementation of SB 1059 to further define the designation process and the informational requirements for future corridor designation applications. The Energy Commission adopted the final regulations in 2008.

Concurrent with the rulemaking, the Energy Commission's *2007 Strategic Transmission Investment Plan* encourages corridor applications requesting designations on non-federal lands to accommodate future transmission projects that would achieve one or more of the following objectives: provide access to renewable resource areas; interconnect with existing federal corridors or with proposed federal corridors identified under Energy Policy Act of 2005 section 368; and preserve existing corridors that may be required for future facility upgrades.

In establishing a statewide corridor planning process, the Energy Commission should work collaboratively with the CPUC, the California ISO, other key state and federal agencies, local and regional planning agencies, IOUs and POUs, generation owners and developers, the public, and other interested groups (2005 IEPR).

The state has made substantial progress on this recommendation. The state has executed a coordinated transmission planning process for renewable energy that includes a significant corridor planning component. The Energy Commission is also actively participating in the RETI process to ensure that environmental issues and land use constraints are addressed during the development of conceptual transmission plans for reaching high-priority CREZs. The Energy Commission's input helps make certain that any short-term, high-priority transmission plans developed in RETI consider these issues before development of project-specific Certificate of Public Convenience and Necessity applications to the CPUC. This helps projects submitted to the CPUC to have a greater likelihood of permitting success.

The Energy Commission's *2009 IEPR* and *2009 Strategic Transmission Investment Plan* will consider the results of RETI as part of a comprehensive evaluation of transmission investments needed to ensure reliability, relieve congestion, and meet future load growth and generation, including, but not limited, to renewable resources, energy efficiency, and other demand reduction measures. This will include an evaluation of potential transmission corridors that may be needed to help achieve state policy objectives.

The Energy Commission should actively participate in the recently initiated federal corridor planning efforts to evaluate issues associated with designation of energy corridors on federal lands in 11 western states, beginning with filing comments in the scoping of the programmatic environmental impact statement. (2005 IEPR)

The state has made substantial progress on this recommendation. In November 2005, the California Resources Agency requested the Energy Commission to represent California in the federal Programmatic Environmental Impact Statement (PEIS) effort to ensure that the PEIS considered the state's energy and infrastructure needs, renewable generation policy goals, and environmental concerns. In December 2005, the BLM designated the Energy Commission as a cooperating agency.

In coordination with the Department of Energy, the BLM, and the United States Forest Service (USFS), the Energy Commission established and coordinated the efforts of an interagency team of federal and state agencies to review proposals to designate new and/or expand existing energy corridors and examine alternatives on California's federal lands. Participating state agencies included the Department of Fish and Game, the Native American Heritage Commission, the Public Utilities Commission, and the Governor's Office of Planning and Research. In addition, the State Lands Commission and the Department of Parks and Recreation provided input and monitored the interagency team's activities. In addition to the BLM and USFS, other federal agencies actively involved included the National Park Service, the Bureau of Indian Affairs, the United States Air Force, the United States Marine Corps, and other Department of Defense services.

The Energy Commission, the CPUC, and the California ISO should implement changes to the California ISO tariff to encourage construction of transmission for renewables.

The state has made substantial progress in implementing this recommendation. On April 19, 2007, the Federal Energy Regulatory Commission (FERC) granted the California ISO Petition for Declaratory Order, which created a new mechanism for facilitating the wholesale rate financing and development of renewable transmission lines, known as the "third category" of transmission. The FERC refers to these third category renewable transmission lines as interconnection facilities designed primarily to connect multiple location-constrained resources (remote renewable resources) to the California ISO-controlled grid.

In response to FERC's action, the California ISO developed an amendment to the tariff to include the Location Constrained Resource Interconnection (LCRI) policy for FERC's consideration. On October 17, 2007, the California ISO Board of Governors approved changes to its federal tariff language and filed the new tariff language with FERC on October 31, 2007. The LCRI policy was effective January 1, 2008.

Natural Gas

Statewide Progress on Natural Gas Recommendations	Substantial	On Track	Improvement Needed
Incorporate new analytical tools in assessing and forecasting natural gas supplies and demand		✓	
Investigate alternative forecasting methods to better assess future natural gas prices		✓	
Examine feasibility of increasing natural gas production from renewable sources		✓	

The Energy Commission will continue to incorporate new analytical tools such as scenario planning and portfolio analysis in assessing and forecasting the state's natural gas supplies and demand to meet reduced greenhouse gas emission targets. The Energy Commission will encourage the Public Utilities Commission to participate in these analytic efforts (2007 IEPR).

The state has made progress on this recommendation. Staff is developing work plans for *2009 IEPR* that include as a main topic the impact of GHG reduction targets on coal use for electricity generation in the rest of the United States and the resulting impacts on demand for natural gas. Staff also plans to analyze the impact of these GHG targets on natural gas demand, supply, price, and infrastructure during the *2009 IEPR* cycle.

The Energy Commission should further investigate alternative forecasting methods in the 2007 Energy Report cycle to better assess future natural gas prices (2005 IEPR).

The state has made progress on this recommendation. To develop a natural gas assessment for the *2007 IEPR*, the Energy Commission hired three consultants to assist in analyzing results from models staff used to derive natural gas prices. The consultants provided an alternative approach and highlighted uncertainties in the inputs and assumptions that could change the outcomes of the models. These views were reported in the *2007 Natural Gas Market Assessment Report*.

The Energy Commission has formed a team of technical staff to continue looking at methods used to derive supply, demand, and price parameters and is discussing new approaches to better assess the uncertainty of natural gas inputs, assumptions, and outputs derived from the models. The team will be analyzing different methods and studies on natural gas and is planning to incorporate their findings in the *2009 IEPR*. Numerous entities currently forecast natural gas prices, and the team will examine some of those forecasts and provide an assessment to the IEPR Committee during the *2009 IEPR* process.

To diversify California's natural gas supply sources, the state can examine the feasibility of increasing natural gas production from more innovative sources. For example, California is rich in biomass resources that are suitable as a feedstock for gasification technologies (2007 IEPR).

The state has made progress on this recommendation. The Energy Commission, through its Public Interest Energy Research (PIER) Program, has recently funded research and development projects supporting the use of biomass as a feedstock for gasification technologies. For example, the Energy Commission provided a grant to Dixon Ridge Farms in Winters for the demonstration of a 50 kW modular gasification system using combined heat and power with biomass residue (walnut waste).

In 2008, the Energy Commission executed two biopower and two biofuels demonstration contracts. For biopower, Growpro, Inc., will demonstrate a simplified gasification technology using forest residue, and UC San Diego will demonstrate the integrated cogeneration of power from forest wood waste using an advanced thermochemical gasification process in parallel with the production of mixed alcohol (primarily ethanol) for blending with gasoline. Medcalf and Eddy and the San Francisco Public Utility Corporation will use fats, oils, and grease for biofuels production, and the Renewable Energy Institute International will use wood waste and rice straw.

The Energy Commission also executed four biomass research, development, and demonstration contracts in 2008 through its Natural Gas Replacement Program, which targeted advanced energy conversion technologies to replace natural gas.

Transportation Energy

Statewide Progress on Transportation Recommendations	Substantial	On Track	Improvement Needed
Implement public goods charge to provide funding for infrastructure, technology and fuels research, analytical support, and incentive programs	✓		
Implement AB 118: form advisory body, develop investment plan, develop and recommend sustainability standards		✓	
Work closely with other states to influence federal fuel efficiency standards			✓
Establish non-petroleum diesel fuel standard		✓	
Update full fuel cycle analysis working with relevant agencies and key stakeholders		✓	

The state should implement a public goods charge to establish a secure, long-term source of funding for comprehensive transportation program that provides funding for infrastructure investment, a broad range of technology and fuels research, analytical support, and incentive programs (2005 IEPR).

The state has made substantial progress on this recommendation. Assembly Bill 118 (Núñez, Chapter 751, Statutes of 2007) created the Alternative and Renewable Fuel and Vehicle

Technology Program. The legislation increases vehicle registration, boat registration, and smog check fees and authorizes the Energy Commission to spend approximately $120 million per year over seven years to develop and deploy innovative technologies that transform California's fuel and vehicle types to help attain the state's climate change policies. The program will deploy alternative and renewable fuels in the marketplace without adopting any preferred fuel or technology.

Move quickly to implement AB 118, beginning with forming the advisory body as directed in the legislation; develop a strategic investment plan for alternative fuel and vehicle incentives, as required by AB 118 to be updated annually; develop and recommend sustainability standards to guide the future development of alternative fuels in California, in partnership with the Air Resources Board (2007 IEPR).

The state has made progress on these recommendations. The Energy Commission has begun implementing the Alternative and Renewable Fuels and Vehicle Technology Program. On January 30, 2008, the Energy Commission approved an Order Instituting Rulemaking (OIR 06-0130-05) to adopt guidelines, definitions, and other provisions necessary for the administration of the program. This rulemaking will develop and adopt regulations that are necessary to clarify ambiguities in statute and create certainty and transparency in the administration of the program. The Energy Commission expects to complete the rulemaking in spring 2009.

In addition, the Energy Commission has established an advisory committee to help develop an investment plan to establish priorities and identify opportunities for the program and describe how funding will complement existing public and private investments, including existing state programs. The Energy Commission prepared a draft investment plan that was discussed at the second advisory committee meeting on July 9, 2008, and expects to adopt the investment plan in early December 2008. The investment plan will be updated annually.

As part of the rulemaking for the Alternative and Renewable Fuels and Vehicle Technology Program, the Energy Commission is developing a set of "sustainability goals" as required in AB 118 that will be reflected in the investment plan and in funding solicitations. To assist in this effort, the Energy Commission established a sustainability working group. One of the key issues under discussion is indirect land use and how its impacts should be measured and considered in project evaluation.

The state should continue to work closely with other states to influence the federal government to double vehicle fuel efficiency standards and enact fleet procurement requirements that include super-efficient gasoline and diesel vehicles (2005 IEPR).

Indirectly, the state has made slow progress on this recommendation. In late 2004 to early 2005, the Energy Commission staff surveyed the level of interest among other states in working together to advocate to the federal government to double the existing the Corporate Average Fuel Economy (CAFE) standards, with many states indicating willingness to pursue this objective.

In October 2005, the Energy Commission filed comments to the docket of the U.S. Department of Transportation's National Highway Transportation Safety Administration (NHTSA), aimed at improving fuel economy of light trucks for model years 2008 to 2011. The Energy Commission requested NHTSA to adopt new CAFE standards for 2008 only and to conduct further analysis for developing higher fuel economy standards for later model years. The Energy Commission stated that the fuel cost used in current analysis was far too low and that using higher fuel costs would lead to higher fuel economy standards.

Although California has not successfully formed a state-level collaboration to directly influence the adoption of higher CAFE standards, the state has implemented landmark regulations that will indirectly improve efficiency of new vehicles sold in California. As directed by Assembly Bill 1493 (Pavley, Chapter 200, Statutes of 2002), the ARB in 2005 adopted regulations to limit GHG emissions from new vehicles sold in California, beginning in model year 2009. New vehicles fully complying with this regulation in 2016 will consume nearly 30 percent less fuel than vehicles built before 2009.

Further, the Federal Energy Independence and Security Act, enacted late last year, increases the CAFE standards from the current level of 27.5 miles per gallon for passenger cars and 22.2 miles per gallon for light trucks (minivans, sport minivans, sport utility vehicles, and pickups) to a combined fleet average of 35 miles per gallon by 2020. This increase is a significant improvement, but is not enough to attain the level of fuel economy that the Energy Commission and ARB determined in 2003 to be both achievable and cost-beneficial.

The state should establish a non-petroleum diesel fuel standard so that all diesel fuel sold in California contains a minimum of 5 percent non-petroleum content that would include biodiesel, ethanol, and/or gas-to liquid components (2005 IEPR).

The state has made progress on this recommendation. The ARB is developing regulations to establish a state Low Carbon Fuels Standard (LCFS) in its proceeding. These regulations will set standards to reduce the average fuel carbon intensity in the state's transportation fuel pool by 10 percent by 2020. Under the LCFS, the ARB is establishing separate standards for gasoline and diesel fuels. Like gasoline, diesel will be required to achieve a 10 percent reduction in its average fuel carbon intensity. The ARB currently considers biodiesel and renewable diesel to be fuels with lower carbon content. Blending in these fuels will increase the renewable content of petroleum fuel. The Energy Commission expects the LCFS to be adopted by spring 2009 and become effective January 2010. The ARB has designated the LCFS as a Discrete Early Action measure under its AB 32 proceedings.

Work collaboratively with the Air Resources Board, key stakeholders, and other relevant agencies to regularly update the full fuel cycle analysis in an open and transparent manner (2007 IEPR).

The state has made progress on this recommendation. The Energy Commission staff is working directly with ARB staff in the LCFS proceeding to document the full fuel cycle assessment conducted during the *AB 1007 State Alternative Fuels Plan* proceeding and to update the California-modified Greenhouse Gases, Regulated Emissions, and Energy Use in

Transportation (GREET) model used in the assessment. The Energy Commission and ARB have agreed to jointly update the GREET model in the future and use the same version in the respective proceedings of the two agencies.

Also, in July 2008 the Energy Commission awarded two contracts to update the full fuel cycle assessment capabilities and assess how land use changes affect GHG emissions, evaluate water impacts associated with all alternative and renewable fuels, analyze new fuel pathways, and evaluate the sustainability of transportation fuels on a full fuel cycle basis. These enhancements to the GREET model and the collective understanding of the sustainability of transportation fuels options will improve the full fuel cycle assessment capabilities of the Energy Commission and ARB.

Petroleum Infrastructure

Statewide Progress on Petroleum Infrastructure Recommendations	Substantial	On Track	Improvement Needed
Develop permitting guidelines based on best practices approach	✓		
Monitor infrastructure impacts of State Lands Commission Marine Oil Terminal Engineering and Maintenance Standards		✓	

The Energy Commission should develop petroleum infrastructure permitting guidelines based upon a "best practices" approach following this inter-agency evaluation (2005 IEPR).

The state has made substantial progress on this recommendation. In May 2008, the Energy Commission published *2008 Best Permitting Practices Guidelines for Liquid Transportation Fuels Infrastructure.*[138] The report recommends guidelines to local, state, and federal agencies, as well as project proponents, for streamlining and coordinating the permitting process for petroleum and other liquid transportation fuel infrastructure projects without compromising environmental protection. The guidelines do not recommend changes to laws, regulations, or agency jurisdictions or responsibilities. The guidelines for the Energy Commission include: continuing and expanding active participation in petroleum and other transportation fuel infrastructure regulatory processes; and facilitating workshops and training forums for agency and stakeholder participants.

Next steps include:

- Provide input to and comments on the Pacific L.A. Marine Terminal LLC Pier 400, Berth 408 Project Supplemental Environmental Impact Statement/Subsequent Environmental Impact Report.
- Track, monitor progress, and provide comments on refinery upgrade and expansion projects, including the ConocoPhillips Rodeo Refinery Clean Fuels Expansion Project.

138 California Energy Commission, May 2008, http://www.energy.ca.gov/2008publications/CEC-700-2008-002/CEC-700-2008-002-SF.PDF.

- Provide training to California Department of Fish and Game biologists and ecologists on permitting energy pipelines.
- Facilitate workshop discussion with agency and energy industry representatives on transportation fuels and related infrastructure issues for the CalFire Office of the State Fire Marshal and the California State Lands Commission.

Monitor the impact on infrastructure development of the State Lands Commission Marine Oil Terminal Engineering and Maintenance Standards (MOTEMS), especially on clean fuels marine terminals in the Port of Los Angeles and Long Beach (2007 IEPR).

The state is on track with this recommendation. The Energy Commission continues to monitor petroleum industry progress in complying with MOTEMS and meet periodically with representatives of the State Lands Commission for status updates on implementing MOTEMS regulations. To date, there is no indication that operations at marine oil terminals would be significantly hindered or that importing fuel would be affected because of compliance.

A recent confidential survey of marine oil terminal operators included questions for oil importers about MOTEMS compliance. The results indicate that operators anticipate no problems. Later this year, the Energy Commission will survey marine terminal operators that import traditional and renewable transportation fuels. The survey will identify which marine terminals, if any, may not be able to comply with MOTEMS because of economic or business plan decisions, and how that will decrease their ability to import clean fuels.

The Energy Commission staff met with State Lands Commission representatives in September 2008 to obtain a report of compliance-to-date for all marine terminals, including those that import crude oil and clean refined products. The information from the survey and the State Lands Commission meeting will be presented at workshops held during the *2009 IEPR* workshop process.

Land Use

Statewide Progress on Land Use Recommendations	Substantial	On Track	Improvement Needed
Require local governments to develop GHG reduction plans		✓	
Form state agency working group to develop and implement efficient land use action plan for the state			✓
Assist municipal utilities in partnering with local governments to incentivize smart growth			✓
Include energy element in local government general plans			✓
Expand technical and financial assistance to regional agencies and local governments		✓	

The state's AB 32 plan should require local governments to develop GHG reduction plans and finance such efforts through the AB 32 administrative fee at a level commensurate with the GHG savings expected from improved land use planning (2006 IEPR Update).

The state has made progress on this recommendation. On June 26, 2008, the ARB released its Climate Change Draft Scoping Plan, under AB 32. The draft plan encourages, but does not require, local governments to develop climate action plans. The scoping plan also calls for carbon fees that could be used "to pay for reductions or achieve other goals related to the program." The Energy Commission supports this plan but continues to believe that climate action plans should be required, not optional, for local governments.

The state should form a state agency working group to develop and implement an Efficient Land Use Action Plan for the state. (2006 IEPR Update).

The state has made substantial progress on this recommendation. In November 2007, the California Environmental Protection Agency (CalEPA) formed the Land Use Subgroup of the Climate Action Team chaired by the Energy Commission and included representatives from several state agencies. The purpose of the subgroup was to develop energy-efficient and carbon-efficient land use recommendations, which were submitted to the ARB for consideration in its Climate Change Draft Scoping Plan in March 2008.

Also, in January 2006, the Governor launched the Strategic Growth Plan (SGP), a proposed set of new policies to leverage partnerships with the private sector, increase synergy between public agencies, and educate thousands of new engineers to build the California of tomorrow. One of these policies was to create the Strategic Growth Council. Senate Bill 732 (pending) would establish a five-member Council to help state agencies allocate SGP money in ways that best promote efficiency, sustainability, and support the Governor's economic and environmental goals. Chaired by the Director of the Office of Planning and Research, the Council will consist of the Secretaries from the Resources Agency, CalEPA, the California Business, Transportation, and Housing Agency, and the California Department of Food and Agriculture.

The Council will award and manage grants and loans from Proposition 84 funds to support the development of sustainable communities. The Council's responsibilities will include establishing application requirements and evaluation criteria for the grant program. It will also coordinate the four member state agencies, as they undertake infrastructure and development projects, to encourage sustainable land use; protect natural resources; improve air and water quality; increase the availability of affordable housing; improve transportation; and meet the goals of the Global Warming Solutions Act (AB 32). Furthermore, it will recommend policies to the Governor, the Legislature, and state agencies that encourage sustainable development, as well as collect and provide data to local governments to help them develop and plan sustainable communities. While the state has little direct say in local land-use planning, the Council will provide leadership and support for local governments.

Under the authority granted to it by Assembly Bill 2021 (Levine, Chapter 734, Statutes of 2006), the Energy Commission should assist municipal utilities in partnering with local governments to incentivize smart growth in their service territories (2006 IEPR Update).

The state has not made progress on this recommendation. The Energy Commission has begun securing staff resources and is developing a strategic approach to attain this goal. However, there is pending legislation that, if passed, could provide indirect assistance. Senate Bill 375 (pending) establishes a process for improving land use and transportation planning in California through a set of regional and local incentives linked to the California Environmental Quality Act and transportation planning and funding. If passed, SB 375 would require the regional governing bodies in each of the state's major metropolitan areas to adopt, as part of their regional transportation plan, a "sustainable community strategy" that will meet the region's target for reducing GHG emissions. SB 375 would also create incentives for implementing the sustainable community strategies by allocating federal transportation funds only to projects that are consistent with the emissions reductions. Companion legislation, Senate Bill 732 (Steinberg), creates a Sustainable Communities Council and allocates $90 million from Proposition 84 for general plans that encourage water conservation, discourage automobile use, promotes infill, protect natural resources and farmland, and are compatible with regional growth blueprints. This will create a potential source of funding implementation of SB 375.

Local governments should be required to include an energy element in their general plans (2006 IEPR Update).

The state has made little progress on this recommendation. No statewide legislation has emerged to require local governments to add an energy element to their general plans. The Governor's Office of Planning and Research is updating the 2003 version of the General Plan Guidelines and may update the section on optional energy elements, based on any new research on this topic.

In the absence of a mandate, the Energy Commission initiated a multi-year $400,000 contract with the San Diego Association of Governments (SANDAG) in June 2007. As part of the contract, SANDAG will develop a "how-to" guide on preparing an energy element for use by other regional and local governments. The Energy Commission is assembling a State Advisory Task Force to guide the project. The task force includes representatives from metropolitan planning organizations, councils of government, and state agencies. They will review and comment on all report drafts and will meet in 2009 to discuss energy and climate change planning at the Blueprint Learning Network workshops in Sacramento.

The state should expand efforts to provide technical and financial assistance to regional agencies and local governments to facilitate climate-friendly and energy-efficient planning and development (2007 IEPR).

The state has made progress on this recommendation. The Land Use Subgroup of the Climate Action Team prepared a report detailing technical assistance the state provides for regional and local agencies to implement climate-friendly and energy-efficient planning and development. The subgroup submitted the report to ARB for consideration in its Climate Change Draft

Scoping Plan. In the Draft Scoping Plan, the ARB states its intention to pursue and investigate strategies to provide stable funding for sustainable local planning and zoning updates.

Further, in August 2008, the Energy Commission began updating the Energy-Aware Planning Guide. This update will provide detailed options for local governments seeking to reduce GHGs by conserving energy in transportation, buildings, and operations. The guide will explain the effects of energy policies on GHG emissions, prescribe more effective relationships between local and regional planning agencies, and describe recent best practices. The Energy Commission expects the updated document to be available in July 2009.

Water and Energy Use

Statewide Progress on Water and Energy Use Recommendations	Substantial	On Track	Improvement Needed
Develop consistent regulatory approach for once-through cooling in power plants		✓	
Update data adequacy regulations with respect to once-through cooling at coastal power plants		✓	

The Energy Commission should update its current Memoranda-of-Understanding (MOU) Agreement with the State Water Resources Control Board (SWRCB), the Regional Water Quality Control Boards (RWQCB), and the California Coastal Commission to develop a consistent regulatory approach for the use of once-through cooling in power plants, including the use of best-available retrofit technologies to minimize impacts on the marine environment. The Energy Commission should also actively participate in the federal Clean Water Act Section 316(b) reviews of coastal power plant once-through cooling impacts.

The state has made progress on this recommendation. Since 2005, the Energy Commission has been working through the MOU Agreement process with the SWRCB, the RWQCBs, and the California Coastal Commission on a policy and regulatory approach to phase out once-through cooling for coastal power plants and increase the use of best available retrofit technologies such as large organism exclusion devices and modern screens at existing coastal power plants to minimize the marine environment impacts of using ocean water for once-through cooling of turbines.

With respect to the federal Clean Water Act Section 316(b) reviews, the SWRCB is California's lead agency. The Energy Commission is continuing to work closely with the SWRCB, the RWQCBs, and the Coastal Commission on a revision/implementation process for Section 316(b) regulations. In May 2008, the Energy Commission provided comments on the SWRCB's *Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling* (March 2008).

The Energy Commission is working with the SWRCB to address the once-through cooling issue from the perspective of maintaining the long-term efficiency and reliability of California's electrical system. The IEPR Committee believes that, in most cases, retiring and replacing or repowering the existing plants using once-through cooling with new facilities using other cooling options would be most beneficial to the state.

Other recent Energy Commission activities in this area include:

- A once-through cooling impact analysis as part of the AB 1632 assessment of California's operating nuclear plants, which became available in September 2008.
- Staff participation in the California ISO's study of aging thermal power plants, including once-through cooling impacts.
- Ongoing staff work with the California Ocean Protection Council.
- PIER funding of a research contract on once-through cooling impacts at the Moss Landing Power Plant in Monterey County.

The Energy Commission should update current data adequacy regulations with respect to once-through cooling at the state's coastal power plants.

The state has made progress on this recommendation. In April 2007, the Energy Commission updated its data adequacy regulations for power plant licensing and site certification. The new requirement augments the biological resources information and applies to proposals for expanding or repowering existing coastal power plants if once-through cooling is involved. Applications for Certification (AFC) must now include recent studies to address the facility's current and expected impacts on marine species. The facility must have completed the studies within the last five years and include complete marine species impact information as required by federal Clean Water Act Section 316(b) regulations. Any proposals for new coastal generation facilities involving once-through cooling must also include these studies.

The Energy Commission approved the El Segundo project using once-through cooling in 2005; however, the project owner filed a 2007 amendment petition requesting a change to dry cooling technology, which is under Energy Commission review.

Since 2005, the Energy Commission has not received any AFCs for existing or new coastal power plants involving once-through cooling. There have been three applications for repowering/modernization projects at coastal power plants, the South Bay Replacement Project in Chula Vista, the Carlsbad Energy Center adjacent to the existing Encina plant in San Diego County; and the Humboldt Bay Replacement Project in Humboldt County. Each of these projects proposed use of dry cooling or reclaimed water rather than once-through cooling. The South Bay project withdrew its application because of land use and site control issues, and the Energy Commission is reviewing the Humboldt and Carlsbad projects.

Glossary of Acronyms

AB	—	Assembly Bill
AFC	—	Applications for Certification
ARB	—	California Air Resources Board
BLM	—	Bureau of Land Management
CAFÉ	—	Corporate Average Fuel Economy
CalEPA	—	California Environmental Protection Agency
California ISO	—	California Independent System Operator
CERTS/EPG	—	Consortium for Electric Reliability Technology Solutions/Electric Power Group
CH_4	—	Methane
CHP	—	Combined Heat and Power
CMUA	—	California Municipal Utilities Association
CO	—	Carbon Monoxide
CO_2	—	Carbon Dioxide
CPP	—	Critical Peak Pricing
CPUC	—	California Public Utilities Commission
CREZs	—	Competitive Renewable Energy Zones
DOE	—	(United States) Department of Energy
EIR/EIS	—	Environmental Impact Report/Environmental Impact Statement
FERC	—	Federal Energy Regulatory Commission
GHG	—	Greenhouse Gas
GW	—	Gigawatt
GWh	—	Gigawatt hours
IAP	—	Intermittency Analysis Project
IEPR	—	Integrated Energy Policy Report
IID	—	Imperial Irrigation District
IMPLAN	—	Input-output model
IOUs	—	Investor-Owned Utilities
LADWP	—	Los Angeles Department of Water and Power
LCFS	—	Low Carbon Fuel Standard
LTTPs	—	Long-Term Procurement Plans
MOTEMS	—	Marine Oil Terminal Engineering and Maintenance Standards
MOU	—	Memorandum of Understanding
MW	—	Megawatt
N_2O	—	Nitrous Oxide
NOx	—	Nitrogen Oxides
NRC	—	Nuclear Regulatory Commission
NRDC	—	Natural Resources Defense Council
NWPCC	—	Northwest Power and Conservation Council
OTC	—	Once-Through Cooling

PG&E	—	Pacific Gas and Electric
PEIS	—	Programmatic Environmental Impact Statement
PIER	—	Public Interest Energy Research
PM2.5	—	Particulate Matter
PRG	—	Procurement Review Group
PV	—	Photovoltaic
REC	—	Renewable Energy Credit
RETI	—	Renewable Energy Transmission Initiative
RFO	—	Request for Offers
RPS	—	Renewables Portfolio Standard
RWQCB	—	Regional Water Quality Control Boards
SANDAG	—	San Diego Association of Governments
SCE	—	Southern California Edison
SDG&E	—	San Diego Gas and Electric Company
SMUD	—	Sacramento Municipal Utility District
SONGS	—	San Onofre Nuclear Generating Station
SWRCB	—	State Water Resource Control Board
TID	—	Turlock Irrigation District
USGS	—	United States Geological Survey
VOC	—	Volatile Organic Compounds
WIEB	—	Western Interstate Energy Board
WGA	—	Western Governors' Association